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Electrical Assessment, Capacity, and Demand Study for Fort Wainwright, Alaska

John L. Vavrin, William T. Brown, Michael R. Kemme, Marcus A. Allen, Wayne J. Percle, Robert T. Lorand, David B. Stauffer, and Kenneth Hudson

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John L. Vavrin, William T. Brown III, and Michael R. Kemme

Construction Engineering Research Laboratory
U.S. Army Engineer Research and Development Center (ERDC)
2902 Newmark Drive
Champaign, IL 61822-1076

Marcus A. Allen and Wayne J. Percle

U.S. Army Engineering and Support Center, Huntsville
4820 University Square
Huntsville, AL 35816-1822

Robert T. Lorand

Science Applications International Corporation
8301 Greensboro Drive
McLean, VA 22102

David B. Stauffer and Kenneth Hudson

WorleyParsons Resources and Energy
The WorleyParsons Group
2675 Morgantown Road
Reading, PA 19607-9676

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Under "Annex 46 Holistic Assessment Toolkit on Energy Efficient Retrofit Measures for Government Buildings (EnERGo)"

Abstract: Headquarters, Installation Management Command (HQ IMCOM) commissioned a study team under the leadership of the Engineer Research and Development Center, Construction Engineering Research Laboratory (ERDC-CERL), to determine the electric power requirements of Fort Wainwright, Alaska (FWA) through the year 2020, and energy supply alternatives to meet these requirements. Of particular importance was that FWA management projected that the installation might experience electrical power shortages during the impending winter of 2006/2007 due to increases in energy demand resulting from troop deployments, new construction at the installation, reduction in the number of facilities scheduled for demolition, and the temporary loss of some Central Heating and Power Plant (CHPP) generating capacity. The study team was dispatched to FWA in May 2006 to: (1) determine if there was an imminent problem, (2) identify the most promising courses of action, and (3) identify options and estimate costs to meet the installation's power requirements through the year 2020.

Executive Summary

Overview

The U.S. Army Installation Management Command (HQ IMCOM) commissioned a study team under the leadership of the U.S. Army Engineer Research and Development Center, Construction Engineering Research Laboratory (ERDC-CERL) to determine the electric power requirements of Fort Wainwright, Alaska (FWA) through the year 2020, and also to determine energy supply alternatives to meet these requirements. Of particular importance was that FWA management projected that the installation might experience electrical power shortages during the impending winter of 2006/2007 due to increases in energy demand resulting from troop deployments, new construction at the installation, reduction in the number of facilities scheduled for demolition, and the temporary loss of some Central Heating and Power Plant (CHPP) generating capacity. A study team was dispatched to FWA in May 2006 to determine if there was an imminent problem and to identify the most promising courses of action. The team was also charged with looking at options for meeting the power requirements for the "short-term," which was defined as the period from October 2007 to 2020. By definition, short-term options were those that would be programmed for funding in the FY 2008–FY 2011 funding cycle, with assumed installation/operation by the winter of 2011/2012.

The study involved six principal tasks:

- *Task 1*: Establishing the generating capabilities of the FWA CHPP under several operating conditions: "nameplate" (as run); maximum power output assuming peak demand conditions; and in conjunction with FWA's electric power import capacity based on existing interties to the local utility (Golden Valley Electric Association or GVEA).
- *Task 2*: Determining the annual electric power requirements through the year 2020.
- *Task 3*: Performing a limited condition assessment of the CHPP-related electrical system to identify critical items in need of repair/replacement, and the costs associated with those items.
- *Task 4*: Determining the ability of the local electric utility and other electric power suppliers to meet FWA electric demands through the year 2020.
- *Task 5*: Identifying options for meeting any electric power shortfalls likely to occur in the immediate winter time frame, and through the

year 2020. This included developing costs for a new substation, as a basis for comparison with an existing estimate for this option.

- *Task 6*: Identifying methods and costs to improve electrical reliability focusing on redundant equipment and systems.

FWA electrical capacity

Table ES1 lists the generating capacity of the CHPP under different operating scenarios, as well as the peak power import capability from existing GVEA interties. The nameplate capacity of the CHPP—nominal steam turbine generator (STG) output ratings based on design conditions—is 18 MW—when all four STGs are in operation (one 3-MW STG, and three-5MW STGs). Under certain conditions, the STGs can be operated to generate up to 25 percent higher output (“5/4” operation), which could yield 22 MW. However, the ability to achieve this higher level or upper bound may be constrained, and cannot be considered a standard operating scenario.

The GVEA intertie to the CHPP has a transformer with a nameplate rating of 7.5 MVA (about 6.5–7 MW depending on power factor). Under colder conditions, such as that encountered during periods of peak demand (winter time), the transformer can be safely operated to about 10–11 MVA (about 8.5-10 MW depending on power factor and temperature). **There is also a “backdoor” intertie which has a capacity of about 5 MW, and is used by GVEA only in emergencies.**

Table ES1. FWA electrical capacity.

	CHPP Electric Power Output (MW)		GVEA Import Capability (MW)		Total FWA Electric Capacity (MW)–No Backdoor	Total FWA Electric Capacity (MW) with Backdoor
Operating Scenario	STG 1	STG 3–5 (Total)	Intertie to CHPP	Backdoor Intertie	Total Capacity	Total Capacity
1. Nameplate	3	15	7-10	5	25-28	30-33
2. “5/4” Nameplate Operation	4	18	7-10	5	29-32	34-37
3.Nameplate–One STG Out	3	10	7-10	5	20-23	25-28
4.Nameplate–Two STG Out	3	5	7-10	5	15-18	20-23

Immediate time frame (winter 2006/2007)

For the immediate time frame one STG is planned to be out of service while connections to the new air-cooled condenser (ACC) are completed (Scenario 3 in the Table ES1). Note that each of the STGs will be taken off-line, one-at-a-time, over an 18-month period. In this scenario, the CHPP output is reduced to 13 MW. However, if an additional STG is taken out of service due to unforeseen circumstances, the CHPP would be reduced to 8 MW output (Scenario 4). To ensure adequate capacity is provided to meet this unforeseen circumstance, 8 MW is the assumed electric power output of the CHPP for the immediate time frame. **In the immediate time frame, the total FWA electric capacity is assumed to be 20–23 MW, assuming the backdoor intertie is used (Scenario 4).**

Short-term (post-ACC project completion)

Once the ACC project is completed, the CHPP will be able to generate its nameplate capacity (Scenario 1). However, if an additional STG is taken out of service due to unforeseen circumstances, the CHPP would be reduced to 13 MW output (Scenario 3). Therefore, to ensure adequate capacity is provided to meet this unforeseen circumstance, 13 MW is the assumed electric power output of the CHPP**. In the short term, the total FWA electric capacity is assumed to be 20–23 MW, assuming the backdoor intertie is <u>not</u> used (Scenario 3).**

FWA electrical demand

The peak electric demand is forecast to be 25.3 MW during the 2006/2007 winter, increasing to 29.3 MW by 2011 and to 32.7 MW by 2020. Figure ES1 shows this information annually. The peak demand growth in the period 2005-2006 is due to:

- *New Hospital*. (There has been faster construction and a higher estimated load than was originally projected.)
- *Heater Block Outlets*. (The increased number of vehicles is associated with higher troop populations.)
- *Modular Barracks*. (The use of modular barracks has increased the floor area for housing.)
- A reduction in the number of facilities scheduled for demolition.

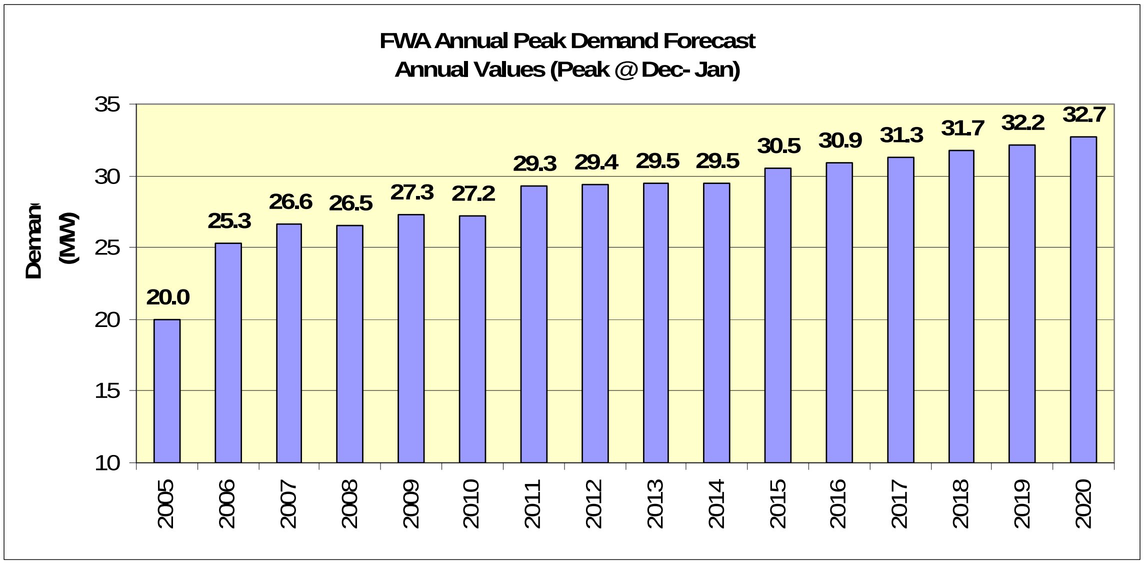

Figure ES1. FWA annual peak demand forecast.

Net electric power shortfall

Immediate time frame

The net power shortfall ranges from 0–10.3 MW depending on the operating scenario. **For planning purposes the net power shortfall is estimated to be 2.3–3.8 MW for the winter of 2006/2007.** This assumes use of the GVEA backdoor intertie (5 MW) and the temperature-dependent load capabilities of the main intertie transformer (8.5–10 MW depending on power factor and temperature), and the availability of only one 5 MW STG and the 3 MW STG.

Short-term time frame

For planning purposes, the net shortage is estimated to range from 3.6–5.1 MW for winter 2007-2008, increasing to 6.3–7.8 MW in 2011 and 9.7–11.2 MW in 2020. The net shortage is based on the scenario in which one 5 MW STG has been taken out of service due to unforeseen circumstances, there is no use of the backdoor intertie, and the installation is not operating the STGs at five quarter capacity. Note that the range corresponds to operating the transformer at its cold weather potential (8.5–10 MW depending on power factor and temperature).

Electric system condition assessment

kV switchgear

The 12.47 kV switchgear is antiquated and should be inspected and refurbished to provide some degree of assurance that the equipment will continue to operate properly in the immediate-time frame. It should be replaced with new switchgear to provide increased safety, increased reliability, and increased capacity to meet future Fort Wainwright requirements. **The cost for this is estimated to be $2.6 million. Note that the U.S. Army Corps of Engineers, Engineering and Support Center, Huntsville (CEHNC) estimate for this work including a new control room is about $21.6 million (see Appendix C)**. However, the CEHNC estimate contains a number of other items in addition to the switchgear.

Other areas surveyed

While the switchgear is the most critical element directly related to the distribution of power from the CHPP as well as from the GVEA intertie, team members from CEHNC briefly surveyed other areas and recommended upgrades to a number of systems. Table ES2 lists the cost estimates developed by CEHNC. (Appendix C lists the estimates' details.)

Table ES2. FWA electrical system upgrade costs.

Task*	Estimated Cost
Replace airfield lighting	$13,928,408
Replace overhead electrical distribution	$16,066,718
Replace underground electrical distribution	$3,336,245
Replace street lighting	$2,550,957
Install generators and switchgear ("Black Start")	$9,407,511

*Note that, except for the "Black Start" generators, which are intended to re-start the CHPP after an outage, these options are not directly related to the CHPP.

Capability of utilities to meet FWA requirements

GVEA has sufficient generation capacity to meet the immediate requirements of FWA. While GVEA expansion plans for the year 2020 are not known, it is assumed that the utility will add capacity as required by its customers, including FWA, sufficient to meet the demands plus a required 30 percent reserve margin. This would also include upgrading the 69 kV transmission line from the utility to FWA, which is currently limited to 30

MW. There are no other significant suppliers of power that could serve FWA.

Options to meet electric power shortfalls

Immediate (winter 2006-2007).

The operational options that FWA can most easily implement, to help reduce its immediate power shortfall is to: (1) take advantage of the cold weather capabilities of its existing intertie; (2) use the backdoor intertie, and (3) run the STGs at 5/4, if conditions permit. These options require no capital cost investments. To close the remaining shortfall, **the most promising option is the installation of a nominal 7.5 MVA transformer from GVEA.** The transformer was available, has been tested by GVEA, and was installed in time for the winter season. The cost to FWA was only for the engineering/installation. (GVEA will maintain ownership of the unit.) For comparison purposes, it is estimated that the outright purchase and installation of such a transformer would cost about $1.3 million.

Other options investigated, but considered included renting diesel generator units either through commercial or Army sources (249th Engineer Battalion, Prime Power), and wheeling power from Eielson AFB. The commercial rental units would cost about $440,000 plus fuel for a 6-month rental period, assuming two-2 MW generators. The Prime Power rental would cost from $500,000 to $750,000, plus additional storage and fuel costs, assuming 1–4.5 MW unit. The units are costly to operate and would potentially affect Title V permit issues. Wheeling several MW of electric power from Eielson will still require a transformer capacity upgrade to the GVEA intertie to use this additional power.

Short term

The most promising options to meet the short-term needs of FWA are increasing transformer/substation capacity. While several transformer capacity upgrade options were evaluated, the 20 MVA option and the 2 x 20 MVA new substation options fully meet or exceed the incremental electric power requirements projected. The latter option has the advantage of being able to meet the full requirements of FWA in 2020 with 100 percent backup capability. In addition, having two transformers rather than one provides an additional level of reliability if one of the transformers should happen to fail or need service. **The cost of the 2 x**

20 MVA substation option is approximately $9.3 million, including $4.0 million for black start diesel generators ($5.3 million without the generators). Note that the CEHNC estimate for a new substation using 2 x 15 MVA transformers is about $7.8 million (see Appendix C).

The options that appear to be worth examining to provide small capacity increases include:

- Automated Volt-Ampere-Reactive (VAR) Compensation at the CHPP would provide perhaps 2.5 MW more output at low cost, with minimal impacts on the plant.
- Modifying STG 1 to enable it to provide 5 MW rather than 3 MW, would enable use of available boiler capacity at modest cost—about $2 million. This option would also help to minimize the electric purchases from the grid, thus helping to minimize overall costs.
- Wheeling power from Eielson AFB also provides a small amount (3 MW) of additional power. However, the amount of extra power available from Eielson AFB will likely vary over time, and cannot be confidently relied on over a long period of time (e.g., to 2020).

The other options examined—replacing existing STGs with larger capacity units, installing diesel generators, or running a dedicated power line from Clear AFS to FWA—all have significant drawbacks.

Electric system reliability improvements

The main suggestions for improving reliability are:

1. Replace existing 12.47kV switchgear
2. Add new utility intertie to 138kV System
3. Upgrade existing 7.5MVA intertie
4. Add “Black Start” diesel generators
5. Conduct condition assessment of CHPP medium and high voltage cables (complete in conjunction with item 1)

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Preface

This study was conducted for Headquarters, Installation Management Command (HQ IMCOM) under Military Interdepartmental Purchase Request (MIPR) 6CCERB1011R, "Annex 46 Holistic Assessment Toolkit on Energy Efficient Retrofit Measures for Government Buildings (EnERGo)"; Project Requisition No. 120872. The technical monitor was Paul Volkman, HQ-IMCOM.

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Unit Conversion Factors

Multiply	By	To Obtain
acres	4,046.873	square meters
British thermal units (International Table)	1,055.056	joules
cubic feet	0.02831685	cubic meters
cubic inches	1.6387064 E-05	cubic meters
cubic yards	0.7645549	cubic meters
degrees Fahrenheit	(F-32)/1.8	degrees Celsius
fathoms	1.8288	meters
feet	0.3048	meters
gallons (U.S. liquid)	3.785412 E-03	cubic meters
hectares	1.0 E+04	square meters
inches	0.0254	meters
miles (U.S. statute)	1,609.347	meters
pounds (mass)	0.45359237	kilograms
square feet	0.09290304	square meters
square inches	6.4516 E-04	square meters
square miles	2.589998 E+06	square meters
square yards	0.8361274	square meters
tons (2,000 pounds, mass)	907.1847	kilograms
yards	0.9144	meters

Terminology Used in this Report

A

ACC	air-cooled condenser
ASHRAE	American Society of Heating Refrigerating and Air Conditioning Engineers

B

B#3	Boiler no 3, (for example)
Btu	British thermal unit

C

CHPP	Combined Heat and Power Plant

D

DA	deaerator
DB	dry bulb (temperature)
dBA	decibels, Acoustic
DG	diesel generator

E

El	electric

F

°F	degrees Fahrenheit
Fort	feet

G

gpm	gallons per minute
GVEA	Golden Valley Electric Association

H

h, hr	hour
Hp	horsepower
Hz	Hertz, (frequency, cycles per sec.)

I

I	current
I&C	instrumentation and controls
in. Hg,a	inches mercury, absolute
ISO	International Standards Organization

K

kV	kilovolt
kVA	kilovolt-amperes
kW	kilowatt

M

Max.	maximum
Min.	minimum
MMBtu	million British thermal unit
MW	megawatt
MWe	megawatt electric
MWh	megawatt-hour
MWt	megawatt thermal

N

NA	not applicable, not available

O

O_2	oxygen
O&M	operation and maintenance
OEM	original equipment manufacturer

P

Ph	phase
psi	lb/square inch
ppb	parts per billion
PRV	pressure reducing valve

R

RH	relative humidity

S

S	Sulfur content of fuel
ST	steam turbine
STG	steam turbine generator

T

t	short ton
TG	turbo-generator, (turbine-generator)
t/h	ton/hour
ton	short ton

U

USD	United States Dollars

V

V	volts
VF	variable frequency

Y

y, yr	year

1 Introduction

1.1 Background

A recent study of the Fort Wainwright, AK (FWA) facility (Vavrin et al. 2005) projected that the installation's electrical demand would exceed its electrical capacity (considering both its internal electrical generation capacity and utility interties) by 2008. Changes that have transpired since that report's publication have further affected the installation's ability to meet its electrical demand. For example, the logistics of the installation's current air-cooled condenser (ACC) project require that a steam turbine generator (STG) be out of service for an extended period while the condenser is removed and replaced with the ACC. This outage reduces the electric generating capacity of the CHPP between fall 2006 and October 2007. Furthermore, FWA management projected that the installation might experience electrical power shortages during the 2006-2007 winter due to increases in energy demand resulting from troop deployments, new construction at the installation, reduction in the number of facilities scheduled for demolition, and the temporary loss of some Central Heating and Power Plant (CHPP) generating capacity. Such circumstances suggest that the timing of the potential supply and demand mismatch may occur in 2007—earlier than previously projected.

The U.S. Army Installation Management Command (HQ IMCOM) commissioned a study team under the leadership of the U.S. Army Engineer Research and Development Center, Construction Engineering Research Laboratory (ERDC-CERL) to assess the situation, to determine the electric power requirements of Fort Wainwright, AK (FWA) through the year 2020, and to determine energy supply alternatives to meet these requirements. A study team was dispatched to FWA in May 2006 to determine if there was an imminent problem and to identify the most promising courses of action. The team explored options for meeting power requirements for the "short-term." For this work, "short-term" was defined as the period from October 2007 to 2020, and included options that would be programmed for funding in the fiscal years 2008–2011 (FY08–FY11) funding cycle, with assumed installation/operation by the winter of 2011-2012. This study reviewed the supply-demand situation in greater detailer detail than previous studies, focusing on reliability issues, and addressing the most promising options for meeting projected power supply shortfalls.

1.2 Objective

The objective of this study is to determine the magnitude of the potential supply-demand mismatch, and to identify options to ensure the adequate supply of electric power for 2006-2007 winter and through the year 2020.

1.3 Approach

The study involved six principal tasks:

1. Establishing the generating capabilities of the FWA CHPP: nameplate, as run, and maximum power output assuming peak demand conditions, as well as FWA's electric power import capacity, based on existing interties to the local utility (Golden Valley Electric Association or GVEA).
2. Determining the annual electric power requirements through the year 2020.
3. Performing a limited condition assessment of the CHPP-related electrical system to identify critical items in need of repair/replacement, and the costs associated with those items.
4. Determining the ability of the local electric utility and other electric power suppliers to meet FWA electric demands through the year 2020.
5. Identifying options for meeting any electric power shortfalls likely to occur in the immediate winter time frame, and through the year 2020. This included developing costs for a new substation, as a basis for comparison with an existing estimate for this option.
6. Identifying methods and costs to improve electrical reliability focusing on redundant equipment and systems.

1.4 Mode of technology transfer

This report will be made accessible through the World Wide Web (WWW) at URL: http://www.cecer.army.mil

2 Current FWA CHPP Electrical Capacity

2.1 Introduction

This chapter reviews and documents the FWA CHPP electrical generation capacity, and the electric utility intertie capacity. In general, the present total CHPP gross electrical generation capacity available at Fort Wainwright is “nominally” 18 MWe (megawatt electric). However, many factors complicate the situation and make it difficult to straightforwardly quantify the electric generating capacity. Section 2.2 discusses these factors in more detail.

The existing GVEA/Fort Wainwright 69 kV interchange capacity is nominally 7.5 MVA, or about 6.4 MW to 7 MW depending on power factor assumptions. However due to the beneficial effects of cold temperatures, this capacity may be increased to 10–11 MVA (8.5 to 10 MW range) during the winter’s peak demand period. An additional “Back Door” intertie, connecting GVEA and a FWA housing area, can also be used to provide an additional 5 MW of power under certain conditions and with certain limitations. These factors are discussed in Section 2.3. Finally, Section 2.4 summarizes these electric capacity considerations.

2.2 CHPP electrical generation capacity

This section describes the existing steam turbine generators (STG), the nameplate ratings, existing capacities, and several relevant factors that affect the generating capacity of the subject turbines. The factors that are discussed are:

- steam turbine generator design values
- capacity limitations on STG-1 resulting from a reduced 10 psig steam demand
- 5/4 (i.e., 125 percent) STG operation and relevant Steam Turbine Limitations and generator limits for STG-3 through STG-5
- the impact of Fort Wainwright’s power factor on generation
- the impact of the ACC on generation capacity for STG-3 to STG-5.

2.2.1 Steam turbine generator description

The plant is equipped with five steam turbine-generators, all manufactured by GE and placed into operation in 1954. The five steam turbines were designed as a combination of backpressure and condensing machines with several different extraction levels. Figure 1 shows the steam turbines, including their present status, configuration, steam pressure levels, and major steam uses. Figure 1 shows STG 3-5 configured with the ACC, which is presently being implemented, and will be fully operational by October 2007.

2.2.1. Steam Turbine Generator 1

Steam Turbine Generator No. 1 (STG-1) is a 5 MW back-pressure machine, designed to supply 100 psig extraction steam for district heating requirements and 10 psig exhaust steam for plant needs. The original design used 10 psig steam for deaeration and for softening. Note that the plant no longer uses steam to regenerate the softener.* Due to the reduced plant demand for 10 psig steam, the STG-1 output has been “derated” to a nominal effective limit of approximately 3 MWe. The 100 psig steam extracted from STG-1 is sent to the Fort Wainwright heating system. The generator is connected at 12.47 kV.

Discussions with plant operators and a review of plant data logs confirm that during the coldest part of winter that STG-1 is able to produce 4.0 MW and slightly above. Plant personnel are confident that STG-1 can reliably provide 4.0 MW in the future (fonecon with Robert Lorand and David Stauffer 2006; e-mail from Patrick Driscoll to John Vavrin).

Table 1 lists the steam turbine parameters, design, operating, and maintenance data for STG-1.

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* Per the original heat and mass balance diagram developed for the CHPP with the steam regenerated softener, the softener required up to 28,800 pph of 10 psig at the peak of winter condition (-50°F with 556,000 pph 100 psig steam sendout, 445,000 condensate return) and down to about 12,500 pph at 25°F (and 230,000 pph steam sendout of 100 psig steam, 184,000 pph condensate return). (Source: H.W. Beecher Architects-Engineers drawing 26-03-11, sheet 73, Ladd Air Force Base Power Plant Extension Heat Balances, Rev. 22 July 1952.)

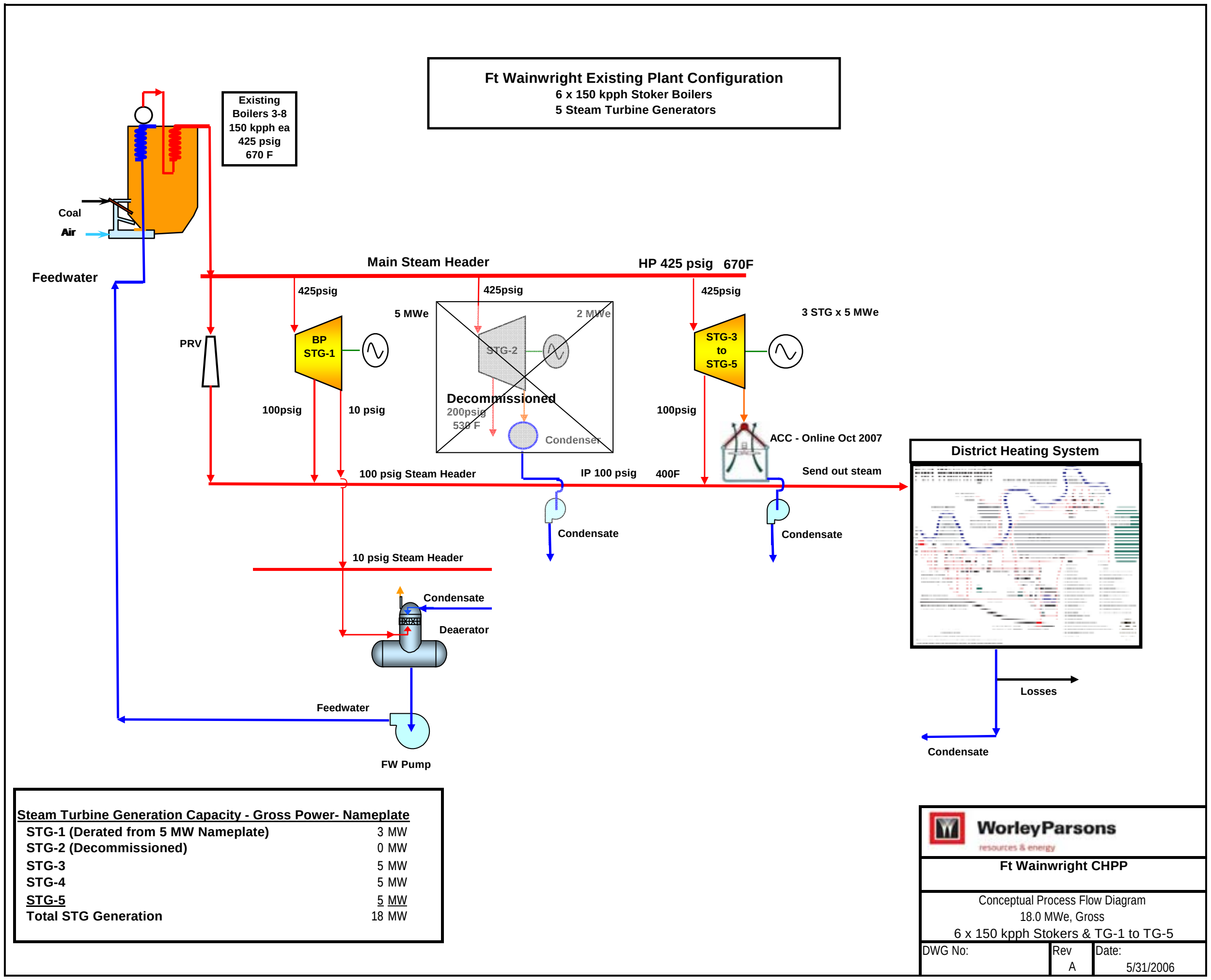


Figure 1. Steam turbine generator conceptual process flow diagram and nameplate capacities.

Table 1. Steam Turbine 1 — characteristics, design, and operating data.

Parameter	Value	Source	Comment
Commissioned	7-26-1954	Assumed	Same time as boilers
STG-1 rating (kWe)	5,000 original 3,000 derated	1 2	STG-1 is presently limited by the 10 psig steam demand. STG-1 can reach 4,000 kWe in the coldest winter period.
Throttle pressure, psig	400	3	
Throttle temperature, F	650	3	
ST stages	10	3	
Automatic extraction at stage	4	3	
Controlled extraction pressure, psig	50 or 100	3	
Generator model	ATB-2	3	
Generator rating, kVA	6,250	3	
Generator voltage	7,200/12,470	3	
Generator power factor	0.8	3	For rating
Exciter model	53-A-1706	3	
STG-1 steam rate, lb/kW	19.5 24.7	4	At 5,000 kW At 3,000 kW
STG-1 max. throttle flow rate, no extraction, lb/h	107,000 74,000	4	At 5,000 kW At 3,000 kW
STG-1 max. throttle flow rate, lb/h	169,000	4	
Coinciding max. extraction flow rate, lb/h	125,000	4	100 psig extraction pressure
Years in service	52	Assumed	Study period start 5/1/05
Annual operating hours for steam turbine plant	8,500	Assumed	Based on 2002, 2003, 2004
Average annual operating hours for STG-1	4,000	Assumed	
Accumulated operating hours for STG-1	200,000		
Last major inspection/overhaul	STG-1–2000	1	Last major overhaul dates are assumed based on circumstantial information provided in referenced sources
Maintenance/repair historical frequency	STG-1–7 yr	5	

Sources:
[1]DESC 2005 [4]
[2]Telecon with Robert Lorand and David Stauffer 2006 [3]
[3]GE 1959
[4]Alaska District 2004
[5]Telecon with Vic Lemay and Dave Brenner 2005

Steam turbine generator performance curves developed by General Electric as part of the turbine design package (dated 1954) were obtained for STG-1. The curves are based on an exhaust back pressure of 10 psig. These have been re-created, since the originals were barely legible (Figure 2). Table 2 lists corresponding performance information.

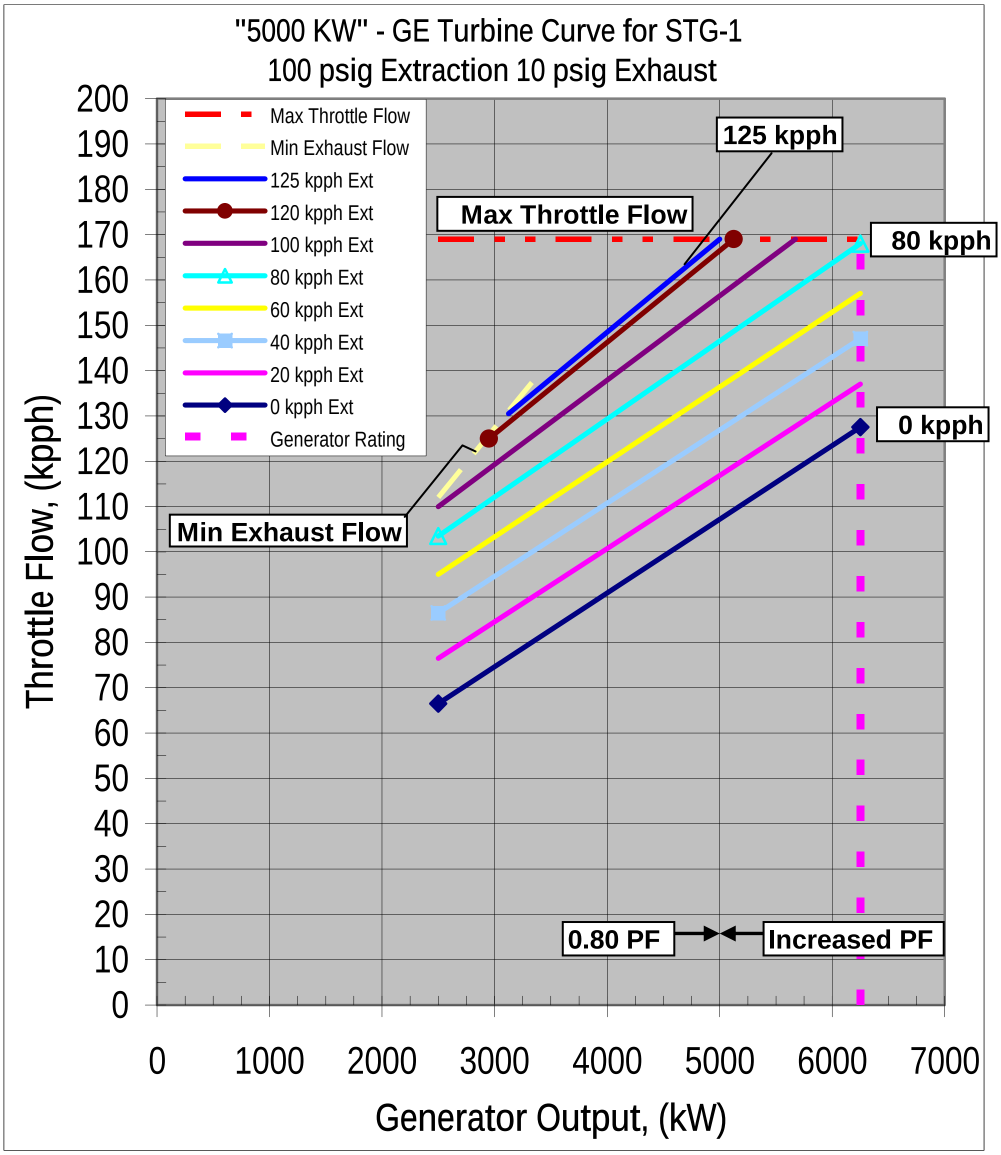


Figure 2. GE steam turbine performance curve for STG-1 with 100 psig extraction and 10 psig exhaust.

Table 2. STG-1 performance data per GE curves.

Gen. (MW)	Throttle Flow (kpph)	100 psig Extrac (kpph)	10 psig Exhaust (kpph)
3	75	0	75
3	85	20	65
3	95	40	55
3	103	60	43
3	112	80	32
3	119	100	19
3	126	120	6
4	91	0	91
4	101	20	81
4	111	40	71
4	120	60	60
4	129	80	49
4	138	100	38
4	146	120	26
4	149	125	24
5	108	0	108
5	117	20	97
5	127	40	87
5	136	60	76
5	147	80	67
5	157	100	57
5	167	120	47
5	169	125	44

Several lessons can be learned from the curves and tables. First, to obtain a given power generation level with a reduced 10 psig steam demand, it requires an increased extraction at the 100 psig level. This explains why the unit has effectively been derated to 3 MW, although it can generate 4 MW when an additional 100 psig heating steam is required.

2.2.1. Steam Turbine Generator 2

STG-2 is a condensing machine rated for 2 MWe and designed to supply 200 psig extraction steam. STG-2 is no longer in operation and has been abandoned in place. Section 6.3.11 summarizes what would be involved in returning STG-2 to service.

2.2.1. Steam Turbine Generators 3 through 5

Turbines 3 through 5 are single casing controlled extraction machines, each with a rated output of 5 MWe at the 12.47 kV generator terminals, which historically discharged to a water-cooled surface condenser with a design exhaust pressure of 1.5 in. Hg,a (inches mercury, absolute). The condenser original equipment manufacturer (OEM) is Graham Manufacturing of NY. The 100 psig steam extracted from STG-3 through STG-5 is sent to the Fort Wainwright heating system.

Cooling water for the condenser has been supplied from the cooling pond. A project currently under way is in the process of replacing the water-cooled condensers with ACC. This project is expected to be completed in October 2007. The ACC design is based on 5 in. Hg,a turbine exhaust pressure at DB ambient temperature of 82 °F (1 percent) (Alaska District 2004). The turbine exhaust pressure range with an ACC is expected to be between 1.5 in. Hg,a and 6 in. Hg,a corresponding to changes in the DB ambient temperature. The current turbine exhaust pressure range is approximately 0.5 to 2.5 in. Hg,a with the cooling pond. Operation with an ACC will reduce the overall turbine cycle efficiency and may reduce the turbine output during the summer months.

Table 3 lists the steam turbine parameters, design, and operating and maintenance data for STG-3-5.

Table 3. Steam turbine 3 to 5 characteristics, design, and operating data.

Parameter	Value	Source	Comment
Commissioned	7-26-1954	Assumed	Same time as boilers
STG rating (kWe)	5,000	1	STG-3, STG-4, STG-5
Throttle pressure, psig	400	2	
Throttle temperature, °F	650	2	
ST stages	10	2	
Automatic extraction at stage	4	2	
Controlled extraction pressure, psig	50 or 100	2	
Generator model	ATB-2	2	
Generator rating, kVA	6,250	2	
Generator voltage	7,200/12,470	2	
Generator power factor	0.8	2	For rating
Exciter model	53-A-1706	2	

Parameter	Value	Source	Comment
STG-3, STG-4, STG-5 steam rate in condensing mode @ 5000 kW, lb/kW	10.91 11.6 13.7	3	At 1.5 in. Hg,a backpressure At 2.5 in. Hg,a backpressure At 5.0 Hg,a backpressure (Exceeds STG design back pressure)
STG-3, STG-4, STG-5 max. throttle flow rate in condensing mode, lb/h	56,000 (1.5inHga) 59,500 (2.5inHga) 68,500 (5.0inHga)	3	Per ACC spec.
STG-3, STG-4, STG-5 max. throttle flow rate in extraction mode, lb/h	190,000	3	At 5,000 kW and 1.5 in. Hg,a
Coinciding max. extraction flow rate, lb/h	180,000	3	100 psig extraction pressure
Years in service	52	Assumed	Study period start 5/1/06
Annual operating hours for steam turbine plant	8,500	Assumed	Based on 2002, 2003, 2004
Average annual operating hours for STG-3, STG-4, STG-5, EA	8,000	Assumed	
Accumulated operating hours for STG-3, STG-4, STG-5, EA	400,000		
Last major inspection/overhaul	STG-3–2005 STG-4–1998 STG-5–2002	2delete 4 5 6	Last major overhaul dates are assumed based on circumstantial information provided in referenced sources
Maintenance/repair historical frequency	Every 5 yr	4	
Future major inspection/overhaul	STG-4–2009 STG-5–2008	5 5	

[1]Telecon with Vic Lemay and Dave Brenner, Fort Wainwright (2005).
[2]General Electric (revised February 1959).
[3]Alaska District (2004).
[4]Telecon with Vic Lemay and Dave Brenner (2005).
[5]e-mail from Patrick Driscoll to Alvin Kam (23 May 2006).
[6]Raytheon Engineers and Constructors (1996).

A steam turbine generator performance curve developed by General Electric as part of the turbine design package (dated 1954) was obtained for STG-3 through 5. The curves are based on condenser back pressure of 1.5 in. Hg,a. The curves were not updated as part of the ACC project. It is assumed that in the coldest part of winter, coincident with the peak electric demands, that this performance curve will be reasonable applicable. That is, it is assumed that STG back pressure following the ACC project will be in the range of 1.5 in. Hg,a for the coldest peak days of winter.

Figure 3 shows the performance curves, and Table 4 lists corresponding performance information. Note that the curves have been recreated here since the originals were barely legible.

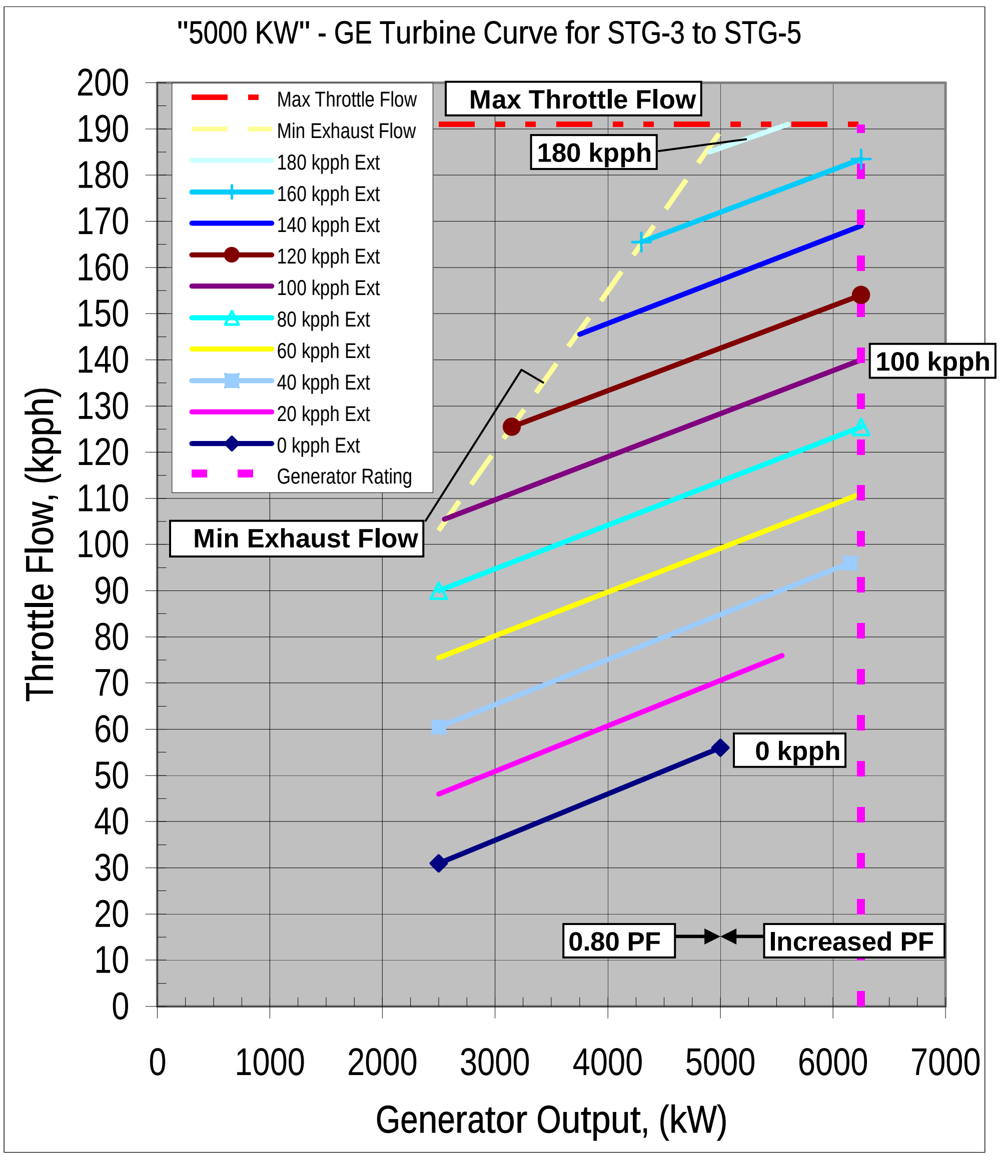


Figure 3. GE steam turbine performance curve for 1.5 in. Hg,a.

Table 4. General electric original performance table for TG-3 through TG-5.

Load (% of Rated Capacity)	Power Factor (%)	Steam Rate (lb/kWh) [note a]	Vacuum (in Hg, a)
125	100	10.50	1.5
100	80	10.91	1.5
75	80	11.23	1.5
50	80	11.98	1.5
25	80	14.51	1.5
Note: a. The legibility of the original is extremely marginal, and the steam rates may be incorrect.			

Several important lessons can be learned from this design information. The data in Table 3 indicate that the steam turbines are rated for 5000 kW, while the generators are rated for 6250 kVA. (Note that with a power factor (PF) of 0.80, that the generator rating is equivalent to the steam turbine rating. [6250 kVA] x [0.80 PF] = 5000 kW.)

In addition, as the data in Table 4 indicate, the STGs are able to produce 125 percent of the rated capacity if the power factor is 100 percent. This information implies that, in general, the STGs are limited by the generators 6250 kVA rating and not the steam turbine capabilities. This observation is further supported by Figure 3, which clearly shows that most combinations of throttle steam flow and 100 psig extraction steam are capable of producing up to 6250 kW with an "increased PF." The PF is a parameter that characterizes the connected load, and it is not something that is typically set.* Thus, knowing the expected PF at the generator is an important part of determining the MW capability of the Steam Turbine Generator. This concept is discussed in greater detail in the next section.

2.2.2 Power factor

A file of hourly power factors recorded for the Fort Wainwright tie-line between 1 January 2004 and 4 May 2006 was obtained. The data includes (presumed erroneous) PF entries that approach zero and with other values approaching negative 1. Figure 4 shows a plot of the power factors falling between 0 and 1. The average PF for all values above zero is 0.83. Ex-

* A power factor (PF) is the ratio of "real power" measured in MW and the apparent power measured in MVA, and reflects the degree of inductance and/or capacitance found in the load. A purely resistive load has a PF of 1.0. Loads with inductive motors and little or no compensating capacitance would have a PF of less than one. PFs assumed for design are commonly taken as 0.80, 0.85, or 0.90 depending on the anticipated load.

cluding the meaningless zero entries, the average power factor for all positive non-zero values is 0.89. Having only this limited set of data, a tieline power factor of 0.85 seems to be a reasonable analytical basis.

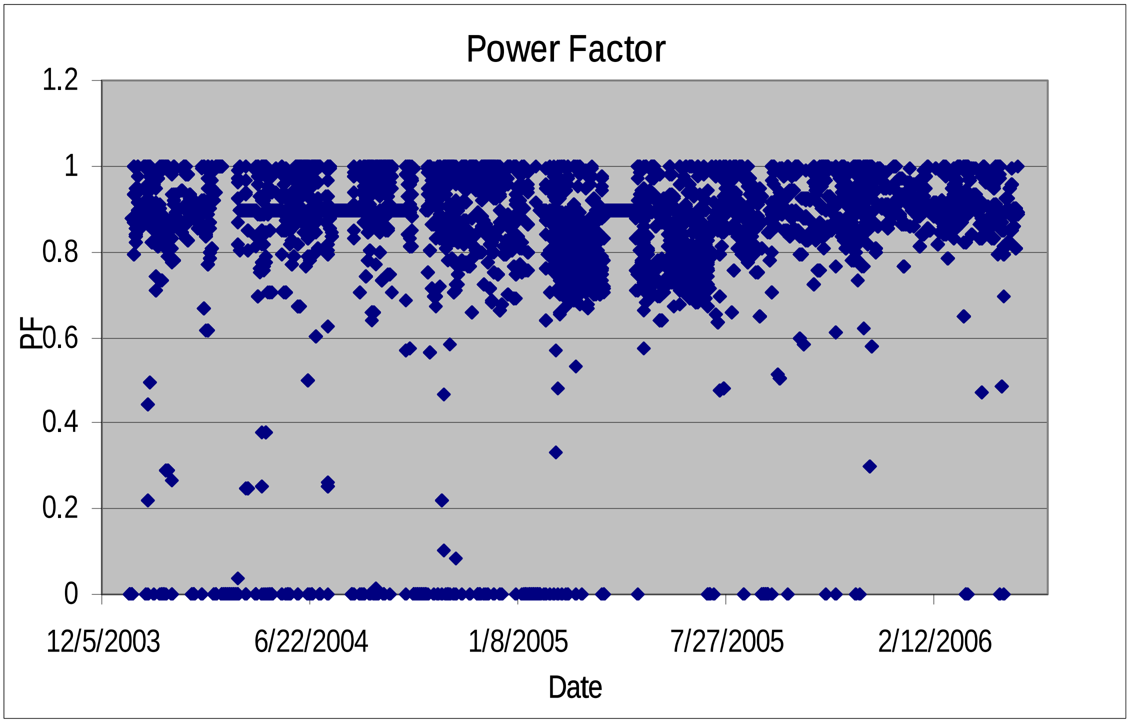
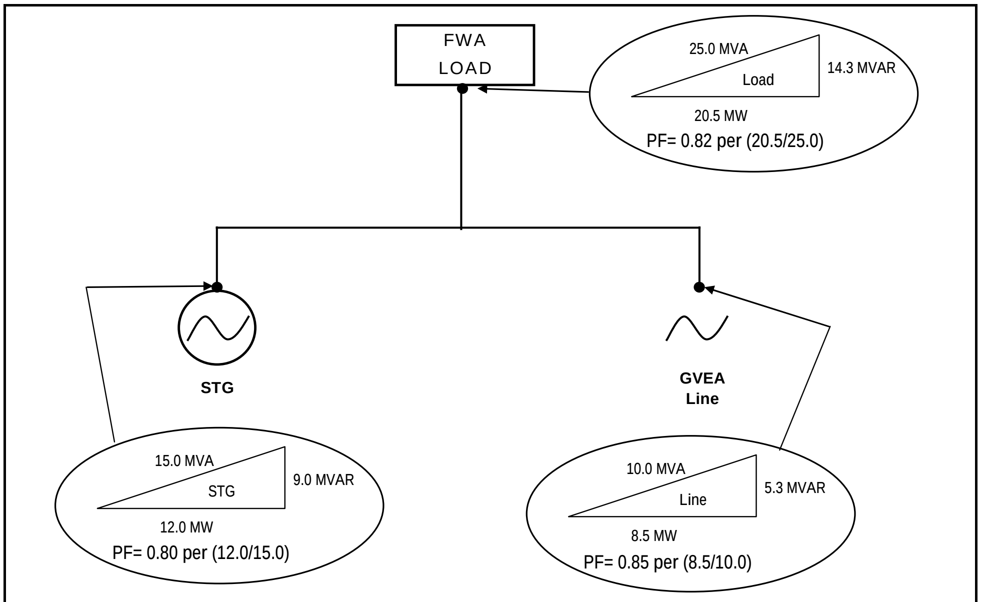


Figure 4. Fort Wainwright tie-line historical power factor from 1 January 2004 to 4 May 2006.

In fact, the local utility (GVEA) requires that the tieline operate at a PF of 0.85 or higher, or GVEA imposes a financial penalty. As a result, the tieline PF is monitored by the CHPP personnel, and the CHPP generators are adjusted if the tieline PF falls below 0.85.

Should the power factor of the Fort Wainwright load dip below 0.85, the operators are able to maintain the tieline power factor above the 0.85 criteria by allowing the steam turbine power factor to drop below 0.85 (and thereby providing more of the required MVAR from the steam turbine generator), as shown in Figure 5.



Balance:	STG	+	LINE	=	Load
MW:	12.0	+	8.5	=	20.5
MVAR:	9.0	+	5.3	=	14.3
MVA:	15.0	+	10.0	=	25.0

Figure 5. An illustration of possible power factors for the FWA load, STG and GVEA intertie.

Unfortunately, neither the power factor of the overall FWA load nor the steam turbine generator is known. Since the steam turbine generator design is based on a power factor of 0.80, and since this value of 0.80 allows the base's load to dip slightly below 0.85 while continuing to operate the tieline at 0.85 or above, the STG design power factor of 0.80 is used in evaluating the steam turbine generators capacity. With a power factor of 0.80, the rated steam turbine generator capacity of 6250 kVA is consistent with a power production of 5000 kW.

2.2.3 Historical power data

Historical generation data was obtained and reviewed for the four operating turbines. Unfortunately, the data for STG-1 is not reliable; the operator logs were inspected instead. The logs demonstrated flat operation at 3000 and 4000 kW. Assuming the STG-1 log data can be trusted, STG-1 operated continuously at 4000 kW between 12 November 2005 (20:00 hrs) and 09 February 2006 (19:00 hrs), or for approximately 88 days. Figures 6 through 8 show hourly power generation data for STG-3 through STG-5 plotted for the calendar year 2005.

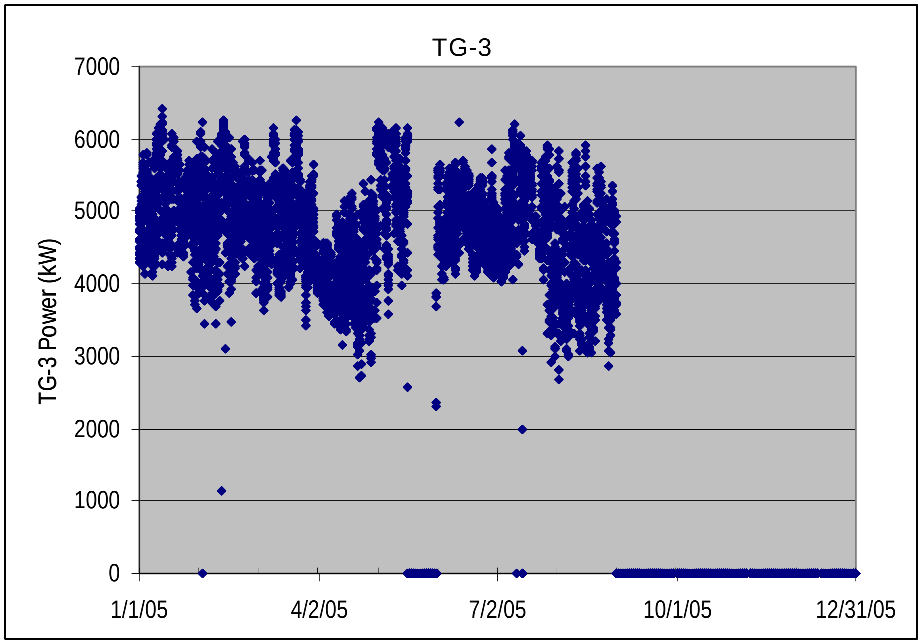


Figure 6. Historical electric generation for TG-3 for 2005.

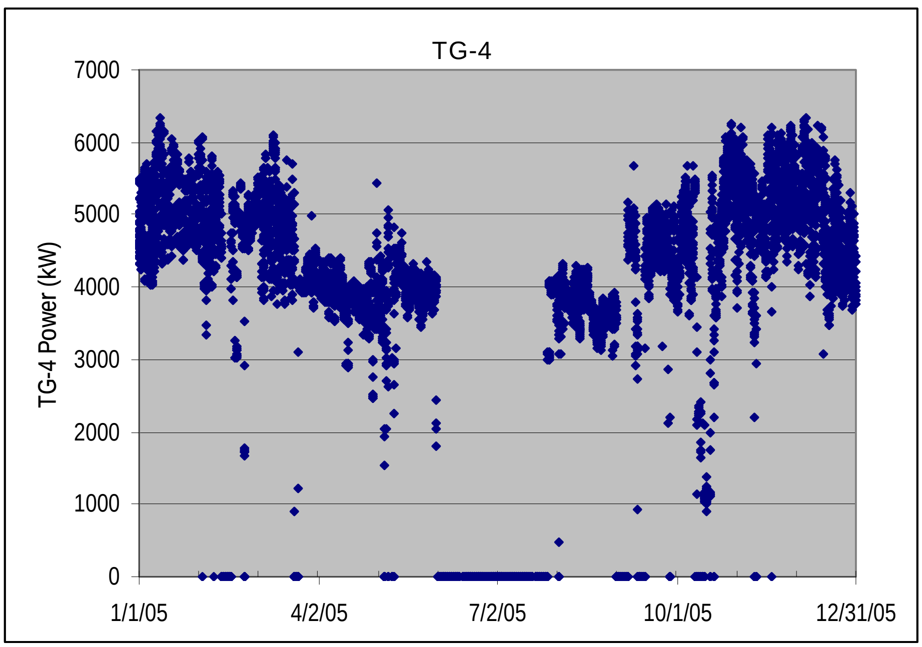


Figure 7. Historical electric generation for TG-4 for 2005.

Clearly these figures display a significant number of operating points (hours) above the 5000 kW rating. To better characterize this data, a histogram was made for each of the three steam turbines based on bin widths of 250 kW. Figure 9 plots this histogram data.

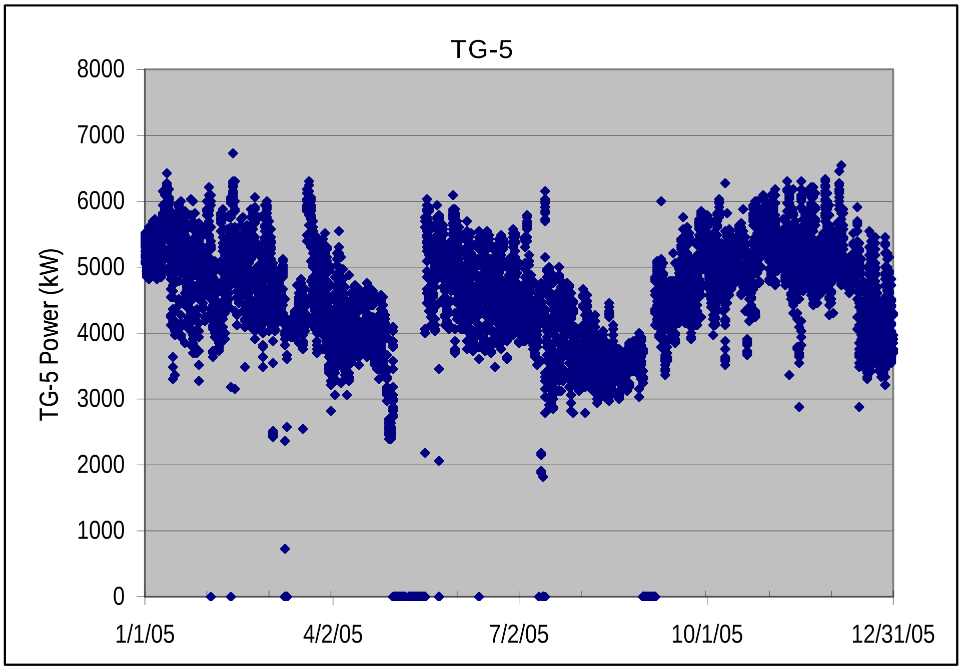


Figure 8. Historical electric generation for TG-5 for 2005.

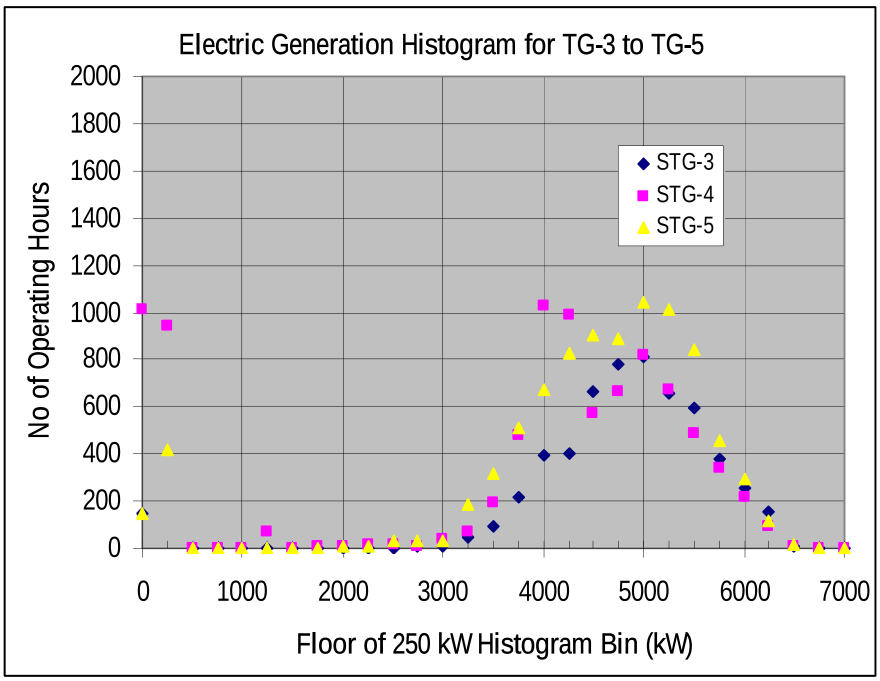


Figure 9. Electric generation histograms for TG-3 to TG-5.

This figure reveals that the most common operating bin is roughly at the steam turbine rating of 5000 kW, but that a significant number of operating hours are logged above this rating. In fact, in 2005, approximately 200 to 300 operating hours were logged at the 6000 kW bin (i.e., 6000 to 6250 kW) for all three steam turbines. Unfortunately, no coincident power factor data was available. Knowing the coincident generation and PF would effectively reveal how the generator has been operated at terms of kVA.

2.2.4 5/4 Operation and generator temperature limits

Discussions with Fort Wainwright plant personnel indicate that the STG are occasionally run above their 5000 kW rating in the overload or 5/4 (five quarters) mode. With the generator being the limiting component in the STG, the maximum power (kW) that can be produced is limited by the generator rating of 6250 kVA and the assumed power factor of 0.80, or 5000 kW. However, plant personnel have indicated that they have talked with the OEM (GE) and have determined that the generator is capable of generating higher than its rated power as long as key operating temperatures are monitored and not exceeded. This means that, under certain circumstances, that the generator might be capable of exceeding its rating of 6250 kVA while maintaining this generator temperature criteria. Unfortunately, as mentioned above, no available information was able to define exactly at what kVA the generator has been safely and continuously operated. Thus for the purpose of the STG capacity analysis, we shall conservatively use the generator rating of 6250 kVA as that which limits the steam turbine electric power generation for TG-3 to 5.

2.2.5 The impact of the steam turbine cooling change

Historically, cooling water for the condenser has been supplied from the cooling pond. A current project will replace the water-cooled condensers with ACC. This project is expected to be completed by October 2007. Each of the steam turbines: STG-3, STG-4, and STG-5 will be equipped with a three-cell, finned tube, A-frame configuration, single-pressure two-stage ACC with variable speed drives. The ACC units will be housed in the new building located east from the existing plant facility. Ancillary services would include a tube bundle washing system, steam heat tracing, cold weather/freeze protection, electrical service, and Instrumentation and Controls (I&C). Table 5 lists the parameters of the ACC design basis (Alaska District 2004; Bagnall et al. 2005).

Table 5. Air-cooled condenser design basis.

Parameter	Value
Condensing Pressure, in. Hg,a	5
Ambient DB temperature, °F (1% ASHRAE)	82
STG steam flow rate, lb/h	68,500
STG extraction steam flow, lb/h	0
STG gross output, MWe	5

The turbine exhaust pressure range with the ACC is expected to be between 1.5 in. Hg,a and 6 in. Hg,a corresponding to changes in the DB ambient temperature. Figure 10 shows the predicted ACC performance curves as a function of inlet dry bulb temperature and steam flow. Unfortunately, the limiting operational point for the design of the ACC is its warm weather performance, and the performance curve does not extend to temperatures below 40 °F.

The current turbine exhaust pressure range with the cooling pond is between 0.5 and 2.5 in. Hg,a. Operation with an ACC will reduce turbine efficiency and may reduce turbine output during the summer months. However, it is expected that during the coldest part of winter that the backpressure of the STGs with the ACC will be approximately 1.5 in. Hg,a. Unfortunately, this cannot be confirmed from the available ACC design data, or operational experience, since the units have not yet operated. Achieving a backpressure of 1.5 in. Hg,a with the ACC should not prevent the STG from achieving its nominal design basis (that is performance consistent with this backpressure.). However, even in the coldest part of winter, the ACC may result is a higher backpressure than that experienced with the cooling pond. Since it is the generator that seems to limit the generation capacity during the winter, this should not have an effect on the generation capacity of the STG*, although it may affect the steam rate (efficiency). For reference, Table 6 lists the site ambient conditions.

* Technically, below an extraction rate of 40,000 pph for the 100 psig steam, the steam turbine (TG-3, 4, and 5) may become the limiting component compared to the generator depending on the power factor. However, since the total 100 psig steam peaks at approximately 300,000 pph (year 2006) per Reference 1 (*Technology Requirements Study for a New CHPP at Fort Wainwright, Alaska*), it is unlikely that the steam turbine will be the limiting component compared to the generator.

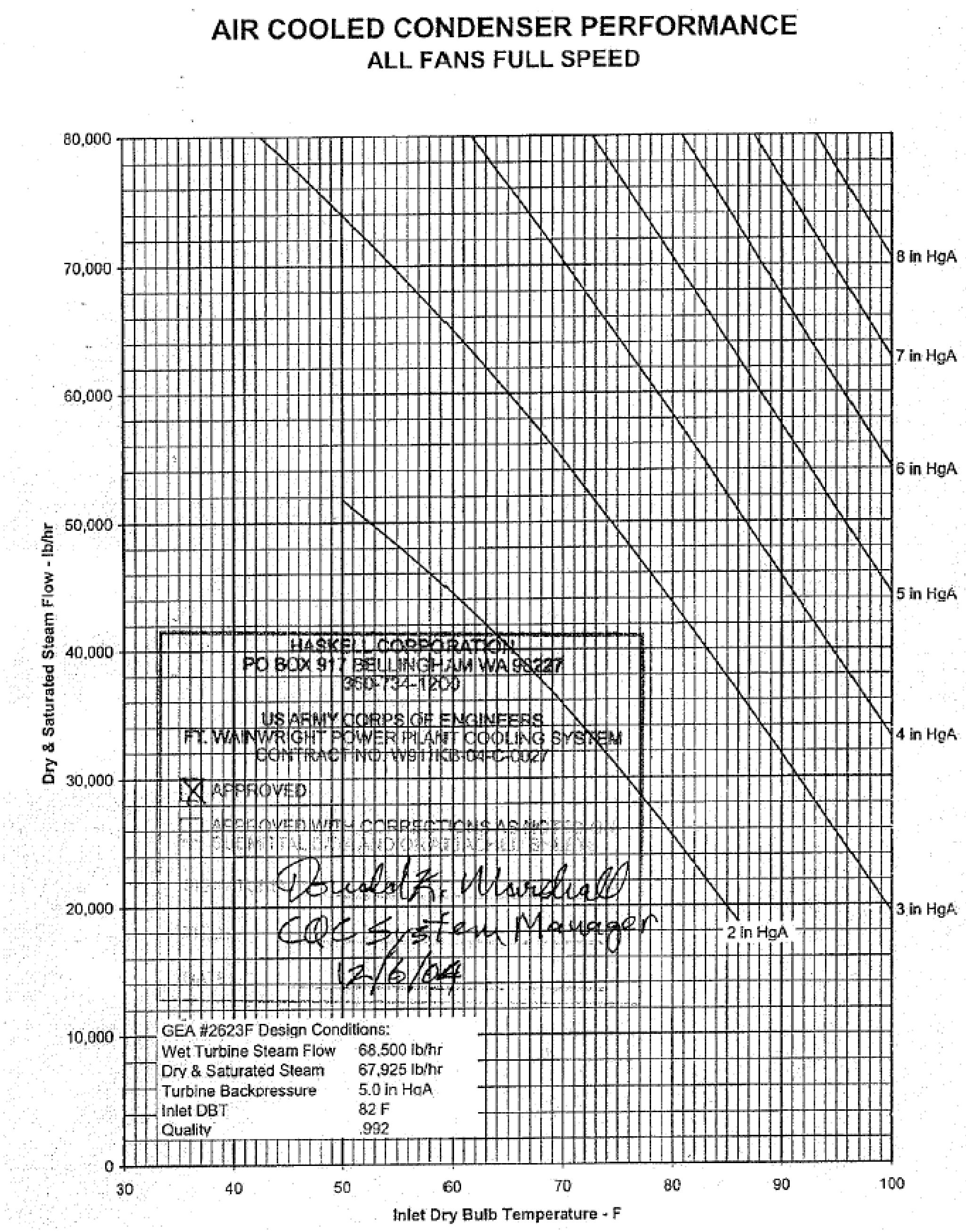


Figure 10. ACC design performance prediction—all fans full speed.

Table 6. Site ambient conditions.

Condition	Measure
Design Dry Bulb Temperature, °F	Winter: −49 (ASHRAE 99%) Summer: 82 (ASHRAE 1%)
Extreme Dry Bulb Temperature, °F	Winter: −60 Summer: 95
Source: Haskell Constructors (undated).	

2.3 Electrical intertie capacity

There are three electrical interties between Fort Wainwright and the local utility, Golden Valley Electrical Association (GVEA). The maximum capacity of the interties was discussed with GVEA during a site visit in the week of 8-12 May 2006 (see Appendix A).

The three ties are:

1. **7.5 MVA Transformer.** A connection exists to the CHPP through a GVEA, 69 kV-12.47 kV, 7.5 MVA, OA transformer. This is the principal connection to the CHPP and Fort Wainwright's electrical distribution system.
2. **A "Back Door" tie.** The back door tie is (historically) intended to be used for emergency purposes and must be switched in manually. The maximum capacity is approximately 5 MW.
3. **A Small Housing tie.** A connection to a small portion of base housing, this portion of base housing is served solely by GVEA and is not connected to the Fort Wainwright's distribution system.

The existing interties between GVEA and Fort Wainwright are at the 69 kV voltage level. The maximum capacity currently available from GVEA at the 69 kV voltage level is about 30 MW and is limited by the maximum capacity of the existing GVEA distribution system (See Appendix A). The maximum capacity could be increased in the short term if a new 138kV connection was added. Adding a 138kV connection in the short term is highly recommended as part of the overall solution to meet Fort Wainwright's electrical requirements.

There are no other agencies with sources of electrical energy in the area with an existing transmission and distribution system that could be connected to the base. Power exchange agreements and wheeling arrangements need to be negotiated with GVEA. The following three sections discuss the three existing electrical interties with GVEA.

2.3.1 7.5 MVA transformer

The capacity of the primary electrical connection between GVEA and Fort Wainwright is limited by a 7.5 MVA GVEA transformer. During conversations with the CHPP personnel it was noted that the GVEA intertie had been operated in the past at about 10 MVA (as opposed to 7.5 MVA). It was determined that transformer's rating should be investigated to determine the maximum power transfer capacity of the intertie. The GVEA transformer is a 7.5 MVA, oil filled, self cooled, and rated for continuous operation at 55 °C temperature rise over ambient (cf. Appendix B). Transformers' ratings are based on the temperature rise over a 24-hr average ambient air temperature of 30 °C. When a transformer is operated at ambient air temperatures with a 24-hr average temperature different than 30 °C, IEEE Standards for Transformers (IEEE 1995) account for this and allow operation at higher load currents at lower temperatures (the load currents produce the temperature rise). Table 7 lists the relationships. (The appropriate correction is circled.)

Table 8 lists the average temperature for Fort Wainwright by month. During the winter months, the average temperature can be expected to be well below 30 °C (86 °F). December, January and February all have average monthly temperatures well below –18 °C (0 °F). In fact, the average monthly temperature for December, January, and February are -21.4–23.4 °C and –19.8 °C respectively (–6.5 °F, –10.1 °F, and –3.6 °F respectively.)

Table 7. IEEE standard for transformer loading as a function of temperature.

Table 4—Loading on basis of temperatures
(average ambient other than 30 °C and average winding rise less than limiting values)
(for quick approximation)
(ambient temperature range –30 °C to 50 °C)

Type of cooling[a]	% of KVA rating	
	Decrease load for each °C higher temperature	Increase load for each °C lower temperature
Self-cooled—OA	1.5	1.0
Water-cooled—OW	1.5	1.0
Forced-air-cooled—OA/FA, OA/FA/FA	1.0	0.75
Forced-oil, -air, -water-cooled —FOA, FOW, and OA/FOA/FOA	1.0	0.75

[a]See 5.1 in IEEE Std C57.12.00-1995. Source: (Alaska District 2004).

Table 8. Average annual and monthly temperatures for Fairbanks, AK.

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
-10.1	-3.6	11.0	30.7	48.6	59.8	62.5	56.8	45.5	25.1	2.7	-6.5
Source: IEEE (1995).											

The transformer is owned by GVEA; GVEA was contacted and asked if the transformer could be operated at 10 MVA during the winter months. GVEA reported back to Fort Wainwright that this was acceptable. GVEA has also indicated that it will perform tests to determine if the transformer exhibits any signs of potential failure.

The normal life of a transformer is primarily dependant on its operating history. Over the life of a transformer mechanical and electrical deterioration occurs that can result in evolution of free gas. It is considered prudent to have the transformer's oil analyzed for these effects.

Table 9 lists the GVEA-calculated temperature dependent capacities based on the IEEE standards and the 7.5 MVA (CityRating.com 2006). Per this table, the 7.5 MVA transformer is capable of 10 MVA or greater for ambient temperatures of 10 °F or below. Considering the average monthly temperatures in December, January and February, and the GVEA calculations, the transformer technically could support nearly 11 MVA. However, for this analysis, the capacity for the transformer is assumed to be limited to 10 MVA during the coldest winter months (considering the age and condition of the transformer, and the variability of ambient temperatures).

Table 9. GVEA calculated temperature based transformer capacities.

Average Ambient Air Temperature (°F)	Ambient Temperature (°C)	Transformer Load (kVA)
-22	**-30.0**	**11625**
-10	**-23.3**	**11125**
0	**-17.8**	**10708**
10	**-12.2**	**10292**
20	-6.7	9875
30	-1.1	9458
40	4.4	9042
50	10.0	8625
60	15.6	8208
70	21.1	7792

2.3.2 The "back door" tie

The "Back Door" tie is a connection between GVEA's distribution lines and a portion of Fort Wainwright's distribution system. The 12.47 kV connection is limited by the conductor size of the existing over head distribution line. The limit for the existing overhead line is approximately 5 MW (See Appendix A). Currently the connection is considered as an emergency or back up option. The connection (or disconnection) must be made manually using disconnect switches. Using this backdoor tie capacity to help address the potential capacity shortfall is considered immediately feasible.

The Back Door capacity could be increased to a higher level, approximately 10 MW. However to use the 10 MW capacity would require new construction by GVEA and new construction at Fort Wainwright. Since the line is not controlled by the CHPP equipment, using the 10 MW capacity or the 5 MW capacity as a permanent solution would remove this portion of the Fort Wainwright base from the CHPP's control and support. Also, there is neither sufficient switching equipment nor existing infrastructure to use the 10 MW. The option to expand this backdoor tie capacity from 5 MW to 10 MW is not considered feasible for any time frame considered.

2.3.3 Small portion of base

A small portion of Fort Wainwright Base housing is connected solely to the GVEA 12.47 kV distribution network. The section connected solely to GVEA does not have any effect on the CHPP generation requirement. There is currently no existing switching equipment or power lines to use an increased capacity for Fort Wainwright. It is not considered practical to increase the capacity of the existing lines and install the necessary infrastructure to use the increased capacity for other areas on the Base.

2.4 Fort Wainwright electrical capacity summary

In summary, the following factors were considered while reviewing the STG generating capacity:

- the STG design values
- the STG capability to operate in its "5/4" mode
- the effect of the FWA power factor, assumed to be 0.80
- the potential effect of the ACC project on the generation capability
- limitations in the 10 psig steam demand and its impact on TG-1.

Table 10 lists the CHPP generating capacity as based on the original design, current limitations, and anticipated peak capacity. These data show the difference between the "Current Nominal Design" value and the "Anticipated Peak Capacity." The "Current Nominal Design" present the design capacity of any operational condition with a power factor of 0.80 and above. The "Anticipated Peak Capacity" presents the capacity anticipated in cold winter conditions also with a power factor of 0.80 and above.

Table 10. Fort Wainwright CHPP electric generating capacity summary.

Steam Turbine	Units	Original Nominal Design[1]	Current Nominal Design[2]	Anticipated Peak Capacity[3,4]
STG-1	MW	5	3	4
STG-2	MW	2	0	0
STG-3	MW	5	5	5[5]
STG-4	MW	5	5	5[5]
STG-5	MW	5	5	5[5]
Total STG	MW	22	18	19.0

Notes/Basis:

1 PF = 0.80, All STG operating per original design, e.g., STG-1, 3-5 @ 6250 kVA.

2 PF= 0.80, STG-1 derated to nominal 3.0 MW per 10 psig steam, STG-2 Retired, STG-3 to 5 @ 6250 kVA.

3 PF= 0.80, STG-1 derated to feasible 4.0 MW in winter per FWA input, STG-2 Retired, STG-3 to 5 @ 6250 kVA. Since the steam flow limits the generation for STG-1, the generator MVA and PF are largely irrelevant.

4 Based on available data and information.

5 The Anticipated Peak Capacity, could be limited in duration depending on operating conditions such as power factor.

The data in Table 11 list the capacity of the existing electrical interties to Fort Wainwright.

Table 11. Fort Wainwright/CHPP electric intertie capacity.

Intertie	Original Capacity	Anticipated Peak Capacity
7.5MVA Transformer	7.5 MVA (6.4MW at 0.85 PF to 6.8 MW at 0.9 PF)	10–11 MVA (8.5 MW at 0.85 PF to 10 MW at 0.9 PF)
Back Door	0-5 MW	5MW
Housing Area	0 MW[1] Not part of CHPP Load	0 MW[1] Not part of CHPP Load

Note: 1. Since the GVEA intertie cannot support the load connected to the CHPP load, it has an effective capacity of zero.

3 Electric Demand and Power Requirement Estimates

3.1 Introduction

This chapter projects FWA electric power demands (loads) from 2006 through the year 2020 and estimates additional power requirements to satisfy these demands. The additional power requirements are based on comparing the CHPP generation capacity and existing utility supplied power, as described in Chapter 2, to the forecast demand. This chapter also explores several scenarios that reflect different operation and equipment availability, including demand forecasts and power requirements for the immediate term and for the period from 2007 through 2020.

3.2 FWA existing loads

Table 12 lists FWA electric power demands for the last 4 calendar years.

The consumption of electricity varies seasonally, with the peak demand occurring during the winter. The calendar year of 2005 is considered to be atypical as a significant number of troops were deployed to address the current conflict in Iraq and Afghanistan. Figure 11 shows the monthly peak demand for the 2002-2005 time period.

Table 12. FWA historical peak demand summary.

Month	2002	2003	2004	2005
Jan	15.5	15.9	17.8	19.7
Feb	14.9	15.4	17.2	18.1
Mar	14.0	14.4	16.4	15.4
Apr	12.9	13.3	13.5	14.1
May	12.1	12.5	13.2	12.8
Jun	11.8	12.2	13.4	12.8
Jul	8.8	9.1	13.5	12.6
Aug	8.8	9.1	13.1	12.7
Sep	11.7	12.1	14.1	12.8
Oct	14.3	14.8	15.2	15.2
Nov	16.3	16.9	17.2	16.7
Dec	15.4	16.0	18.3	16.8

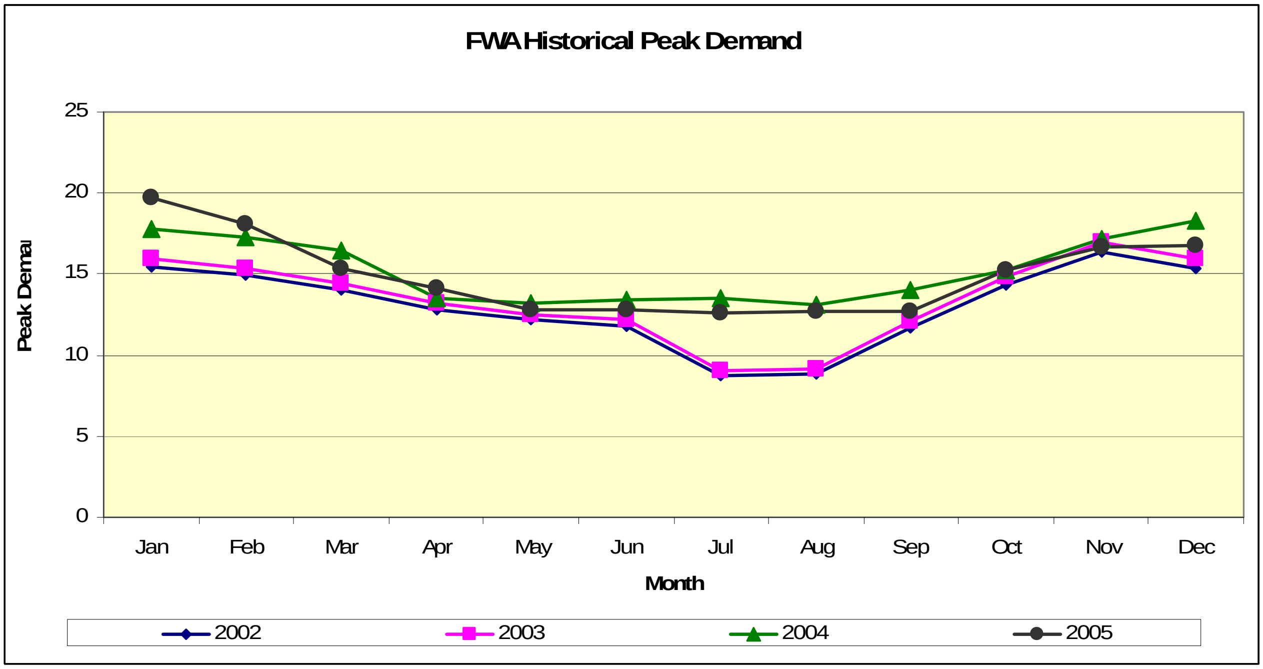


Figure 11. FWA historical electric peak demand.

Figures 12 and 13 present hourly demand profiles on high demand days. The profiles show that the peak typically occurs around 9:00–10:00 AM and that the range of demand is approximately 4 MW.

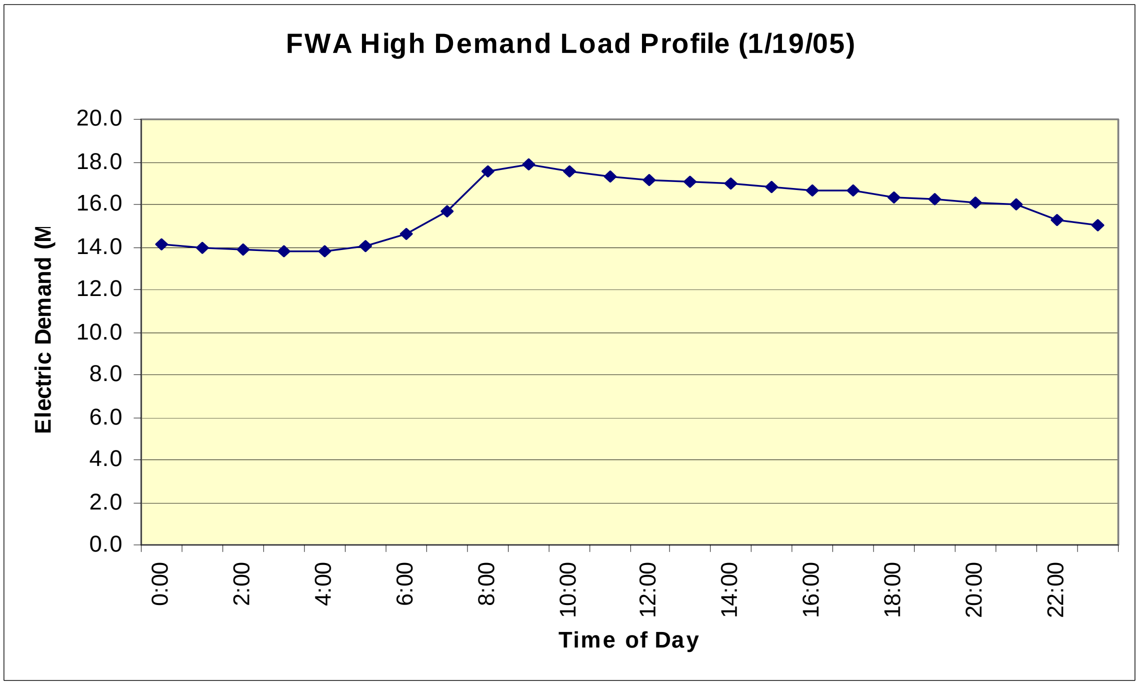


Figure 12. Peak day hourly demand profile (2005).

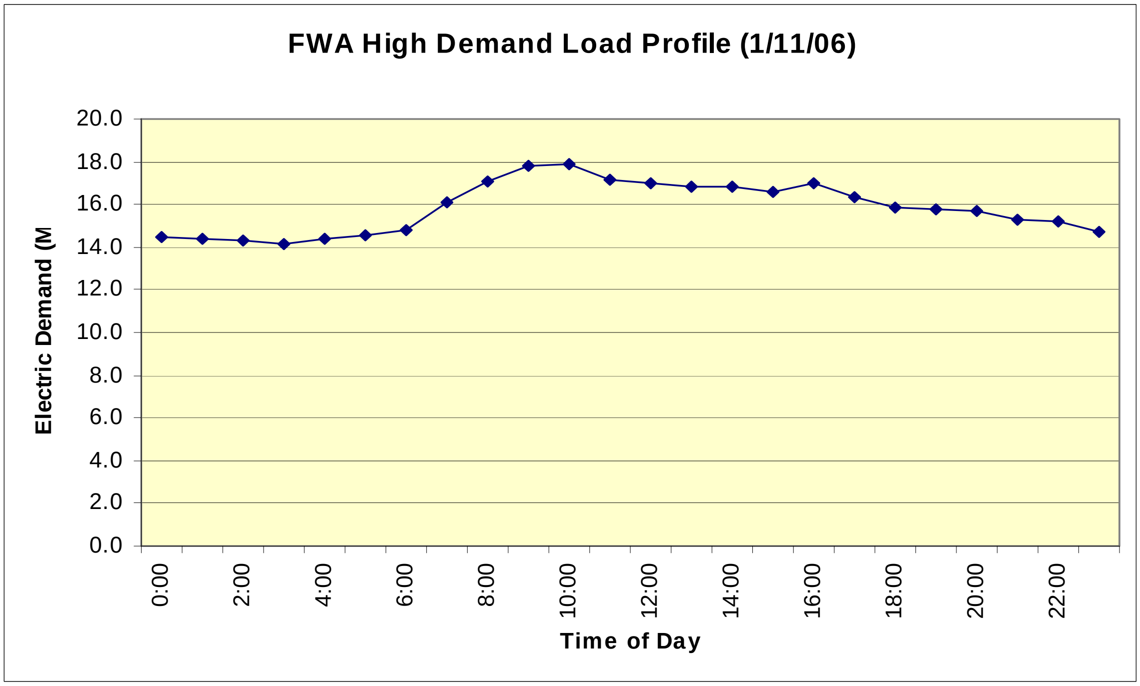


Figure 13. Peak day hourly demand profile (2006).

A regression was conducted on the daily data to see if there is a good correlation between peak demand and the number of troops on the installation. Figure 14 shows the data and the linear regression. The R^2 for the fit is 0.46 which is considered to not be a good fit—the impact of troop population accounts for approximately 45 percent of the change in the peak electrical demand. A good regression is considered when the R^2 is greater than 0.8. The results of this model indicate that a model for the peak demand would include multiple data sets that would likely include troop population, outdoor dry bulb temperature, and building area.

3.3 FWA future loads

3.3.1 Load growth methodology

The process of estimating the future peak demand is based on estimating the energy impacts of planned construction/demolition activity in combination with assumed annual escalation rates. The following section outlines the specifics of the methodology.

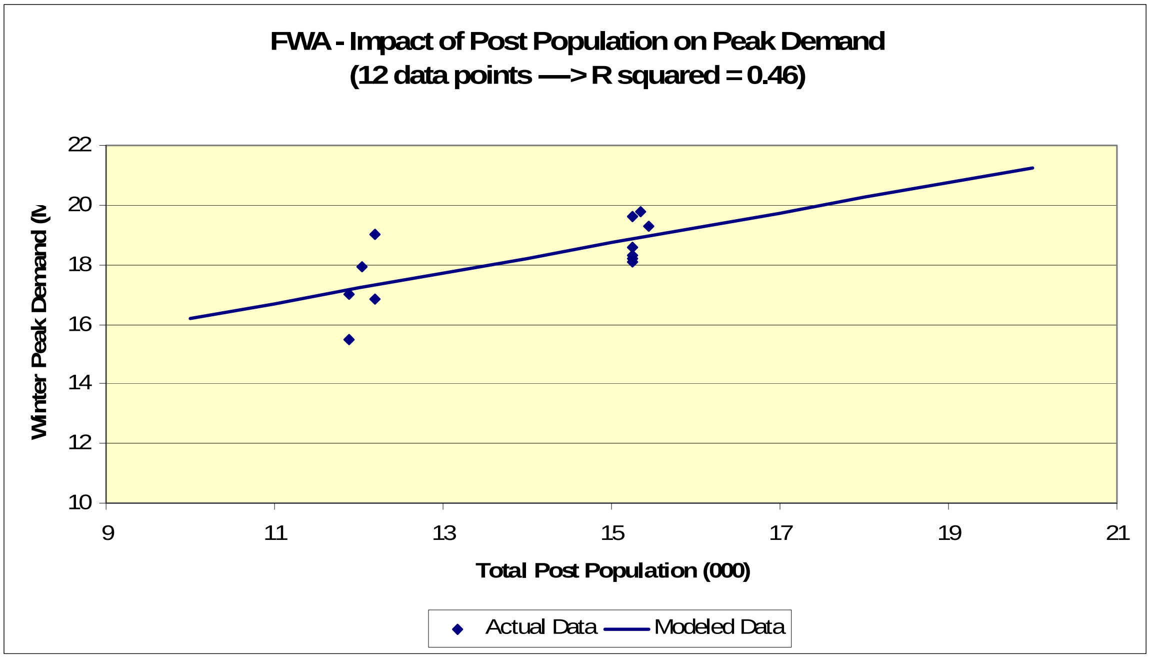


Figure 14. Troop population vs. peak electrical demand.

Step #1: Establish baseline

The data presented above on the historical electric load for 2004 is used to establish a baseline. From a weather perspective, 2004 is considered to be a representative year. There were 13,479 degree days in 2004 vs. an average of about 13,405 degree days for the 1997–2004 period. While this is a bit lower than the 30-year average of 13,914 degree days (96.9 percent), it reflects recent weather trends.* With the good weather agreement and the typical troop population, calendar year 2004 is used as the baseline for the electric demand.

3.3.1. Step #2: Identify planned construction projects

Data obtained from FWA on future projects is used as the basis of estimate for the changes in loads through FY2014. The FWA Master Planning Department provided information on the currently planned projects.† The data on the new building floor area and, where applicable, associated demolitions (for projects denoted as "replacement") were obtained from

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* Degree day data for Fort Wainwright obtained from the following website: http://www.wunderground.com/history/airport/PAFB/2004/12/29/MonthlyHistory.html

† Per discussions with Maria Driscoll and Trevor White.

the DD1391s for each project and from the IFS database. The total number of planned projects as of April 2006 is 86.

3.3.1. Step #3: Identify planned demolition projects

Many projects include a demolition phase to the project. Typical projects assume that the demolition occurs as part of the construction project. In this case, the model estimates the increase in electric load based on the incremental change in the building area. Due to the new increased need for housing on FWA, recent planning strategies have the demolition of existing housing taking placed in a differed fashion. In addition, the demolition of the old hospital is estimated to take place 1 year after the new hospital initiates full operation.

3.3.1. Step #4: Estimate energy intensity factors

Since the change in building area forms the basis for analysis, factors for electricity demand, electricity consumption, heating demand, and heating consumption are required to estimate the impact. There is no metered data available at FWA to use a reference. An investigation of sources of energy intensity data for buildings in Alaska resulted in no useful data.* As a result, FWA -specific data was used based on the baseline data and the overall building area on the installation. The analysis uses the following factors:

- Electricity Demand Intensity: 2.28 W/sq ft
- (19.8 MW/yr * 1,000,000 W/MW/8,672,061 sq ft)
- Electricity Consumption Intensity: 12.75 kWh/sq ft
- (110,553 MWh/yr * 1,000 kWh/MWh/8,672,061 sq ft).

This approach takes into account the diversity factor of the loads and captures each building's contribution to the peak demand of the facility.

Two projects were estimated using alternate approaches. These were the new hospital and the addition of electrical load associated with new Stryker vehicle HBOs.

* Sources reviewed included Department of Energy (DOE) Energy Information Administration (EIA), Alaska Energy Office, University of Alaska-Fairbanks, and various reports. The EIA data was regional and not likely to be representative of the Fairbanks climate. The data available from the other sources was primarily for single family homes.

The one new facility that was calculated using an alternate method was the new Bassett Hospital. On reviewing construction documents and interviewing personnel from the Corps of Engineers, the following load information was obtained.

The 2000 design document estimates the hospital peak demand to be 3.8 MW. The revised current value from the AE Firm estimates the peak demand at 4.5 MW. According to the Corps Office and the AE Firm, the hospital is scheduled for turn-over to the DPW this fall (06/07) for minor interior work and then the accreditation process; the expected load is only 50 to 70 percent of the peak, or 2.5 MW this winter. It is not until mid-2007, when the hospital is fully functioning (with patients) and accredited, that the peak demand will have an impact on installation demand. Therefore, the modeled peak demand for the new hospital is:

- 2006/07: 2.5 MW
- In 2007/08: 3.8 MW (4.5 MW x 85 percent Diversity Factor)
- Stryker Heater Block Outlets (HBOs).

In 2006, there will be a significant number of Stryker vehicles on the installation for the first time. These vehicles will require the use of the heater block outlets (HBOs) during the winter months to ensure that the vehicles will start during severe winter weather. No detailed information is available for the load profile of the heaters or the total number of vehicles that will be plugged into the parking lot receptacles during the installation peak time period of 9:00–10:00 AM. The investigation group estimated that the load would be approximately 1,000 kW. This load exists only in the winter; the model that incorporates the load corresponds with the data listed in Table 13.

3.3.1. Step #5: Calculate coincident demands and total annual consumption values

The above factors are applied to the net change in building area for each project. Coincident peak demand means the demand of the building during the same hour as the entire installation (and the CHPP) experiences its maximum demand.

Table 13. Stryker impact on peak demand.

Month	Demand During Post Peak Hours (kW)
January	1,000
February	1,000
March	1,000
April	500
May	0
June	0
July	0
August	0
September	0
October	500
November	1,000
December	1,000

Step #6: Assign probability of construction factor

The probability of construction factor takes into account that not all proposed projects get funded and constructed. The probability factors were provided by Master Planning Department and the PARO. The factor is applied to the energy impact calculations. For example, a project may be estimated to have peak demand of 100 kW and when the probability factor of 60 percent is incorporated; the estimated final impact of the project is then applied at 60 kW.

3.3.1. Step #7: Estimate construction completion date

Information on projects provided by the Master Planning Department indicates the year in which funding will be requested. Master Planning and the PARO assigned dates of the estimated building occupancy date. The model assumes that the significant electric impacts to the installation occur on building occupancy.

3.3.1. Step #8: Estimate monthly impact values

It is assumed that the demand and consumption characteristics of the new buildings will be consistent with the demand and consumption characteristics of existing facilities as calculated from the base year data. Table 14 lists the profile information.

Table 14. Monthly electric characteristics.

Month	Electric Profile: Percent of Peak Demand	Electric Profile: Percent of Annual Consumption
Jan	100.0%	9.9%
Feb	92.4%	8.6%
Mar	91.9%	9.1%
Apr	76.8%	7.2%
May	70.7%	7.3%
June	74.2%	7.1%
July	75.3%	7.2%
Aug	74.7%	7.3%
Sept	70.2%	7.4%
Oct	78.8%	8.6%
Nov	91.4%	9.8%
Dec	99.0%	10.3%

3.3.1. Step #9: Add impact values to baseline values

The monthly values for each project are added to the corresponding base period figures starting at the appropriate construction completion date. This results in the load forecasts for the 2005–2020 period.

3.3.1. Step #10: Estimate annual changes for period beyond planning cycle

3.3.2 Planned projects

The FWA Master Planning Department provided a summary of the planned projects requesting funding through FY 2011. The data in Table 15 summarize the planned projects for FWA as of March 2005.

The data in Table 15 show that a total of more than 6.8 million sq ft of building construction is planned with an associated demolition of 2.0 million sq ft which results in a net addition of 4.8 million sq ft of planned new construction. These planned construction projects are used as the basis for estimating electric load growth through 2020. Table 16 lists the electric characteristics of new projects, and calculated values for the probability of construction.

Table 15. FWA planned projects.

Project Name	Project Number	Fiscal Year	Site Approved	New Project Area (ft2)	Demo Area (ft2)	Deferred Demo FY	Project Net (ft2)	Probability of Construction	Estimated Building Occupancy Date
Ice Skating Rink Change House	58146	2003	YES	3,600	0	NA	3,600	100%	*17Mar05
Vehicle Maintenance, IBCT	58551	2003	YES	66,000	0	NA	66,000	100%	Apr-05
Family Life Center	59920	2004	YES	2,450	0	NA	2,450	100%	*9-Jun-05
Ammo Supply Point	56922	2004	YES	21,037	0	NA	21,037	100%	*29-Jun-05
Building 4062				15,891	0	NA	15,891	100%	Sep-05
Building 4063				16,851	0	NA	16,851	100%	Sep-05
Building 4064				16,807	0	NA	16,807	100%	Sep-05
Building 4056				16,332	0	NA	16,332	100%	Sep-05
Building 1063				16,851	0	NA	16,851	100%	Sep-05
CH&PP Repair	48777	2004	YES	0	0	NA	0	100%	Sep-05
Mezzanine Expansion	60594	2004	YES	1,250	0	NA	1,250	100%	*12-Oct-05
Vehicle Maintenance	57354	2003	YES	36,370	0	NA	36,370	100%	*14Nov05
Family Housing Replacement	61726	2006	YES	148,840	0	FY11	148,840	100%	Jan-06
Family Housing Replacement	56388	2003	YES	60,060	0	NA	60,060	100%	Feb-06
Modified MOUT and R	55847	2004	YES	4,757	0	NA	4,757	100%	Apr-06
Pallet Processing Facility	56921	2004	YES	59,391	(69,700)	NA	(10,309)	100%	Apr-06
Alert Holding Area	56951	2004	YES	96,271	(69,700)	NA	26,571	100%	Apr-06
Bassett Hospital Replacement	34810	2000-2005	YES	253,361	0	FY08?	253,361	100%	May-06
Barracks Complex, N	47125	2005	YES	99,124	(68,400)	NA	30,724	100%	Jun-06
Whole Brks Renew, Program	58048	2004	YES	55,800	(28,277)	NA	27,523	100%	Jul-06
Multipurpose Training, YTA	42031	2003	YES	17,600	0	NA	17,600	100%	Aug-06
Modular Barracks		2006	YES	148,534	0	NA	148,534	100%	Aug-06
Utility Upgrd, Oak & Santiago	59918	2004	YES	0	0	NA	0	100%	Sep-06
WBR, Santiago Ave.	46789	2005	YES	88,242	0	FY10	88,242	100%	Sep-06
Family Housing Replacement	57074	2004	YES	41,376	0	NA	41,376	100%	Sep-06
Family Housing Replacement	57785	2004	YES	212,910	0	NA	212,910	100%	Oct-06
Util Upgrade, Montgomery & Oak	59917	2003	YES	0	0	NA	0	100%	Oct-06
Stryker HBOs								100%	Oct-06

Table 15. FWA planned projects (continued).

Project Name	Project Number	Fiscal Year	Site Approved	New Project Area (ft2)	Demo Area (ft2)	Deferred Demo FY	Project Net (ft2)	Probability of Construction	Estimated Building Occupancy Date
Helipad	61527	2006	YES	0	(10,710)	NA	(10,710)	100%	Jun-07
Aircraft Maintenance	41753	2005	YES	52,540	(52,539)	NA	0	100%	Aug-07
Power Plant Cooling	53735	2002	YES	0	0	NA	0	100%	Oct-07
507th Signal Information System Facility	61500	2006	YES	9,400	0	NA	9,400	100%	Dec-07
SBCT - New Construction	59028	2005	YES	150,340	0	NA	150,340	0%	May-08
Construct Replacement	60198	2005	YES	130,470	0	NA	130,470	0%	May-08
Construct Replacement	60210	2005	YES	167,340	0	NA	167,340	100%	May-08
Barracks Complex	46790	2006	YES	83,069	0	NA	83,069	100%	May-08
Bassett Hospital Replacement	34810	2000-2005	YES	0	(155,226)	FY08?	(155,226)	100%	Jun-08
Family Housing Replacement	62512	2006	YES	122,610	(183,408)	NA	(60,798)	100%	Oct-08
Family Housing Replacement	62321	2007	YES	181,920	0	FY10	181,920	100%	Mar-09
Family Housing Replacement	62513	2007	YES	157,380	0	FY10	157,380	100%	Mar-09
Construct Replacement	62514	2007	YES	106,140	0	FY10	106,140	100%	Mar-09
Barracks Buyout	61530	2009	YES	114,635	0	NA	114,635	100%	Oct-09
Training Support Center Upgrade	64757	2,009.0	YES	24,000	0	NA	24,000	50%	Jun-10
WBR, Santiago Ave.	46789	2005	YES	0	(157,788)	FY10	(157,788)	100%	Jun-10
Family Housing Replacement	62321	2007	YES	0	(199,080)	FY10	(199,080)	100%	Jun-10
Family Housing Replacement	62513	2007	YES	0	(276,672)	FY10	(276,672)	100%	Jun-10
Construct Replacement	62514	2007	YES	0	(114,048)	FY10	(114,048)	100%	Jun-10
Family Housing New Construction	66212	2008	YES	168,450	0	NA	168,450	100%	Sep-10
Family Housing New Construction	66213	2019	YES	179,000	0	NA	179,000	100%	Sep-10
Family Housing New Construction	66214	2019	YES	180,540	0	NA	180,540	100%	Sep-10
Railhead Operations Facility	61503	2,010	YES	6,000	0	NA	6,000	80%	Mar-11
Air Support Operations Facility (3rd ASOS)	61507	2,010	YES	27,700	(25,915)	NA	1,785	20%	Mar-11

Table 15. FWA planned projects (continued).

Project Name	Project Number	Fiscal Year	Site Approved	New Project Area (ft2)	Demo Area (ft2)	Deferred Demo FY	Project Net (ft2)	Probability of Construction	Estimated Building Occupancy Date
Army Community Service Center	61529	2013	YES	80,000	0	NA	80,000	30%	Mar-15
SBCT Complex	64018	2012	YES	238,307	0	NA	238,307	100%	Jun-15
Mission Support Training	57726	2019	YES	60,000	0	NA	60,000	0%	Mar-20
Mission Support Training PH2	58049	2019	YES	25,000	0	NA	25,000	0%	Mar-20
Mission Support Training PH4	58051	2019	YES	50,000	0	NA	50,000	0%	Mar-20
Mission Support Training Facility	58053	2019	YES	21,000	0	NA	21,000	100%	Mar-20
172nd SBCT 4-Plex COFs	58187	2019	YES	66,426	(34,767)	NA	31,659	40%	Mar-20
Cold Regions Research & Engr Lab (CRREL)	61506	2019	YES	16,500	(16,359)	NA	141	20%	Mar-20
Construct Child Development Center (6w-5yrs)	61526	2019	YES	24,650	(9,118)	NA	15,532	20%	Mar-20
Fisher House	61528	2019	YES	5,000	0	NA	5,000	0%	Mar-20
C-130 and C-17 Mock-up	62018	2019	YES	4,113	0	NA	4,113	0%	Mar-20
Construct Known Distance Range	63340	2019	NO	5,400	0	NA	5,400	25%	Mar-20
Aviation Task Force Complex	64019	2019	YES	1,037,845	(147,941)	NA	889,904	0%	Mar-20
Chip Barn	66189	2019	YES	7,840	0	NA	7,840	10%	Mar-20
Unit Maint Hangar Replacement	29554	2019	YES	54,508	0	NA	54,508	0%	Apr-20
Expand Shopping Center (3.0 Module)	66013	2019	YES	15,005	0	NA	15,005	60%	Jun-20
Modified Record Fire Range	16716	2019	YES	2,400	0	NA	2,400	100%	Aug-20
Total				6,867,093	(2,041,250)		4,825,842		

Table 16. Estimated new project energy impact.

Project Name	Project Number	New Project Peak Demand (kW)	Demo Peak Demand (kW)	Total Coincendent Peak Demand (kW)
Ice Skating Rink Change House	58146	8.2	0.0	8.2
Vehicle Maintenance, IBCT	58551	150.7	0.0	150.7
Family Life Center	59920	5.6	0.0	5.6
Ammo Supply Point	56922	48.0	0.0	48.0
Building 4062		36.3		36.3
Building 4063		38.5		38.5
Building 4064		38.4		38.4
Building 4056		37.3		37.3
Building 1063		38.5		38.5
CH&PP Repair	48777	0.0	0.0	0.0
Mezzanine Expansion	60594	2.9	0.0	2.9
Vehicle Maintenance	57354	83.0	0.0	83.0
Family Housing Replacement	61726	339.8	0.0	339.8
Family Housing Replacement	56388	137.1	0.0	137.1
Modified MOUT and R	55847	10.9	0.0	10.9
Pallet Processing Facility	56921	135.6	(159.1)	(23.5)
Alert Holding Area	56951	219.8	(159.1)	60.7
Bassett Hospital Replacement	34810	578.5	0.0	2500.0
Barracks Complex, N	47125	226.3	(156.2)	70.1
Whole Brks Renew, Program	58048	127.4	(64.6)	62.8
Multipurpose Training, YTA	42031	40.2	0.0	40.2
Modular Barracks		339.1	0.0	339.1
Utility Upgrd, Oak & Santiago	59918	0.0	0.0	0.0
WBR, Santiago Ave.	46789	201.5	0.0	201.5
Family Housing Replacement	57074	94.5	0.0	94.5
Family Housing Replacement	57785	486.1	0.0	486.1
Util Upgrade, Montgomery & Oak	59917	0.0	0.0	0.0
Stryker HBOs				1000.0

Table 16. Estimated new project energy impact (continued).

Project Name	Project Number	New Project Peak Demand (kW)	Demo Peak Demand (kW)	Total Coincendent Peak Demand (kW)
Helipad	61527	0.0	(24.5)	(24.5)
Aircraft Maintenance	41753	120.0	(120.0)	0.0
Power Plant Cooling	53735	0.0	0.0	0.0
507th Signal Information System Facility	61500	21.5	0.0	21.5
SBCT - New Construction	59028	0.0	0.0	0.0
Construct Replacement	60198	0.0	0.0	0.0
Construct Replacement	60210	382.1	0.0	382.1
Barracks Complex	46790	189.7	0.0	189.7
Bassett Hospital Replacement	34810	0.0	(354.4)	(1050.0)
Family Housing Replacement	62512	279.9	(418.8)	(138.8)
Family Housing Replacement	62321	415.4	0.0	415.4
Family Housing Replacement	62513	359.3	0.0	359.3
Construct Replacement	62514	242.3	0.0	242.3
Barracks Buyout	61530	261.7	0.0	261.7
Training Support Center Upgrade	64757	27.4	0.0	27.4
WBR, Santiago Ave.	46789	0.0	(360.3)	(360.3)
Family Housing Replacement	62321	0.0	(454.5)	(454.5)
Family Housing Replacement	62513	0.0	(631.7)	(631.7)
Construct Replacement	62514	0.0	(260.4)	(260.4)
Family Housing New Construction	66212	384.6	0.0	384.6
Family Housing New Construction	66213	408.7	0.0	408.7
Family Housing New Construction	66214	412.2	0.0	412.2
Railhead Operations Facility	61503	11.0	0.0	11.0
Air Support Operations Facility (3rd ASOS)	61507	12.6	(59.2)	0.8

Table 16. Estimated new project energy impact (continued).

Project Name	Project Number	New Project Peak Demand (kW)	Demo Peak Demand (kW)	Total Coincendent Peak Demand (kW)
School Age Services (CDC 6-12 yrs)	60054	41.9	(75.3)	(18.4)
HOT Tactical Operation Center	60978	0.0	0.0	0.0
Arctic Vehcile Parking Garage (TMP)	61239	12.8	0.0	12.8
Construct Provost Marshal Office	61502	73.5	(14.9)	62.3
Replace Fire Station 2	61505	27.2	(9.6)	17.6
Construct MP & Signal Company Opns Facility	61509	56.8	0.0	56.8
Replace Unheated Warehouse Buildings	61531	0.0	(85.7)	0.0
Replace Heated Warehouse Buildings	61532	0.0	(92.4)	0.0
Vehicle Covered Storage (SBCT)	65090	15.1	0.0	15.1
Military Working Dog Facility	61224	7.7	(2.3)	5.7
One Stop Facility w/ ACS	61225	16.3	(249.4)	(108.4)
Post Office	61242	6.2	(10.0)	4.2
Medical Admin Building	61501	25.1	(47.8)	1.2
Replace & Consolidate Fire Stations 1 & 3	61504	11.8	(47.3)	2.3
Replace Melave Gym w/Pool	61508	85.0	(101.2)	4.0
Automated Combat Pistol Range	62302	12.1	0.0	12.1
Band Facility	65104	6.6	(65.2)	0.0
Pedestrian Access Bridge for Live-Fire Training Area	65217	7.2	0.0	7.2
Youth Center Expansion	65751	1.1	(6.7)	0.5
Intelligence Operations Facility (IOF)	58907	0.0	0.0	0.0

3.3.3 Load forecast

Using the peak electric load profile for the base year case and applying the load forecast methodology; the monthly forecast of electrical load growth was estimated for both the near- and long-term periods. The near-term forecast focuses on the installation's immediate requirement (Figure 15). This load forecast will be used to evaluate the magnitude of the expected supply shortfall for the upcoming winters. The key drivers for load growth in the near-term include:

- *New Hospital*—Faster construction and higher estimated load than originally projected.
- *Heater Block Outlets*—Increased number of vehicles associated with higher troop populations.
- *Temporary Barracks*—Increased floor area for housing.

The long-term forecast focuses on the installation's requirements through the year 2020 (Figure 16). This load forecast will be used to evaluate the long-term options for electrical supply to the installation.

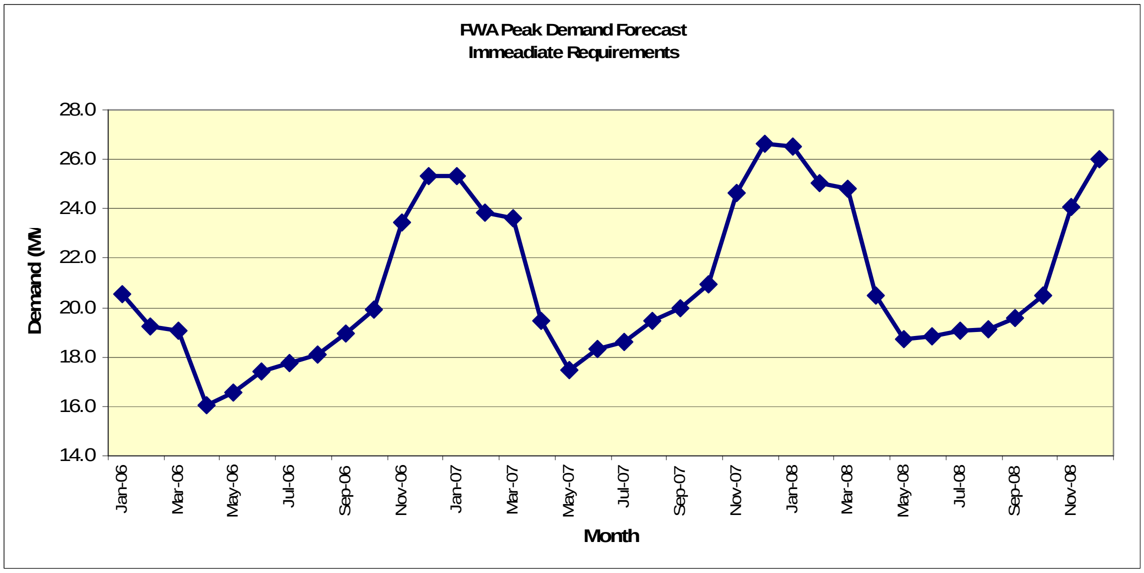

Figure 15. FWA near-term monthly peak demand forecast.

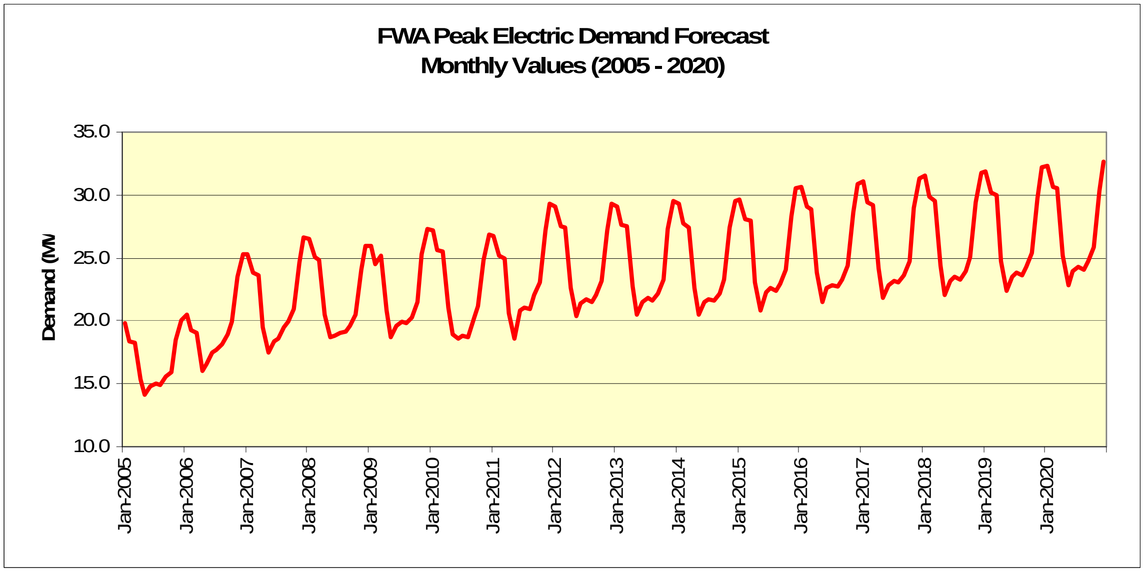

Figure 16. FWA monthly peak demand forecast.

The load forecast shows that FWA electric demand will be 30 MW in 2015, which exceeds the combined capacity of the CHPP and GVEA intertie. Figure 17 shows the annual forecast of peak demands.

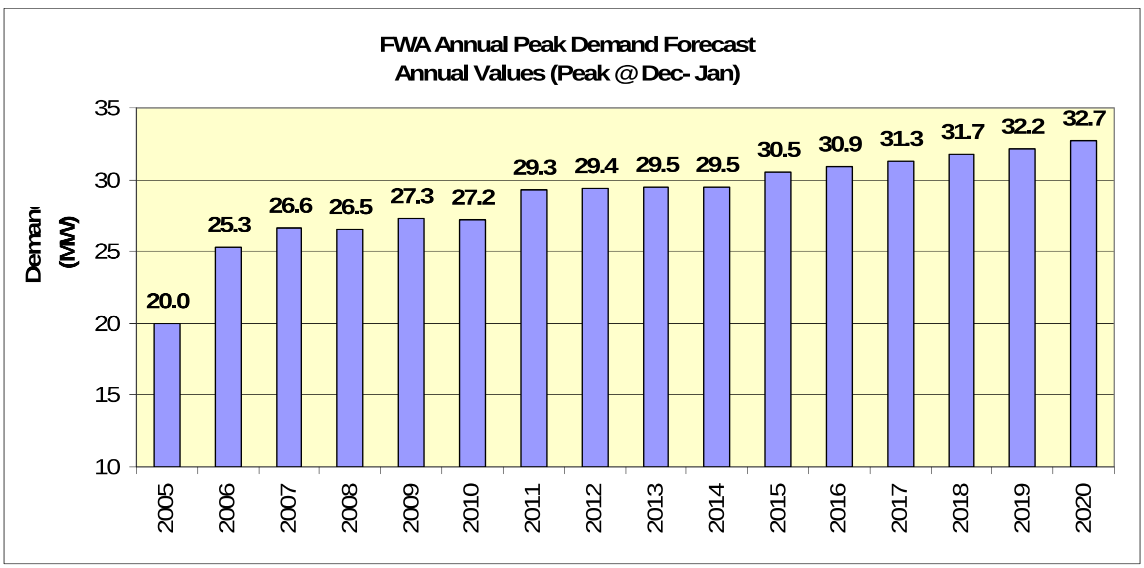

Figure 17. FWA annual peak demand forecast.

Figure 18 shows the annual energy consumption.

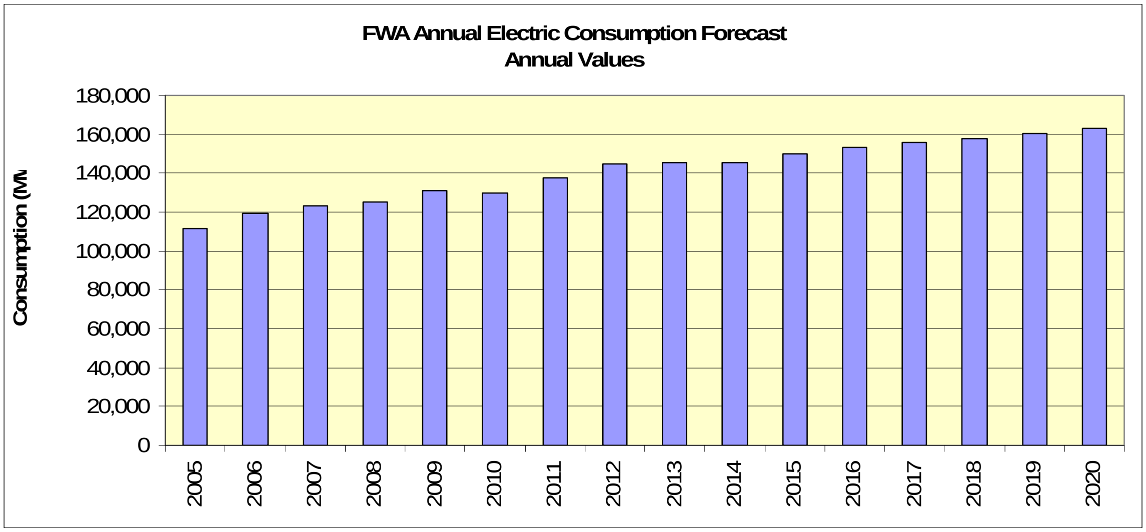

Figure 18. FWA annual peak electricity consumption forecast.

3.4 FWA electric power requirement estimates—near-term

The electric power to meet the above demand will involve operation of the CHPP, import from GVEA, and possibly additional sources of supply. The anticipated power requirements are a function of assumed operating scenarios, as the following section describes.

3.4.1 Baseline supply scenario

Under normal circumstances, when all four steam turbine generators are available, the CHPP can generate a nominal 18 MW. In addition, the GVEA intertie can provide approximately 7 MW, based on its 7.5 MVA nominal rating. This brings the total available supply to 25 MW. However, as a result of the ACC project, each of the five MW steam turbine generators will be required to be taken off-line for 6 months, sequentially, so that the plant will be short 5 MW over a period of 18 months. The maximum power provided under this baseline scenario during the winter of 2006/2007 is 20 MW (Table 17). This is 5.3 MW less than needed to meet the near-term demand requirement of 25.3 MW projected for the winter of 2006/2007. In addition, factoring in the possibility of an unplanned outage of one of the two remaining 5 MW STGs results in a power shortfall of as much as 10.3 MW.

3.4.2 Nameplate supply scenario

GVEA has indicated that it is willing to let FWA use its backdoor intertie, if needed by FWA to meet "emergency" power requirements. Under this "nameplate" scenario, the maximum power provided would be 30 MW, of which 25 MW would be available to meet the winter 2006/2007 demand (Table 18). This falls 0.3 MW short of meeting the demand requirements. However, should an unplanned loss of an additional 5 MW STG occur, the supply would be reduced to 20 MW, resulting in a 5.3 MW power shortfall (see Figure 19).

Table 17. Baseline scenario—maximum electric supply (MW).

	Supply						
Month	Total	3 Turbine #1	5 Turbine #3	5 Turbine #4	5 Turbine #5	7 GVEA Intertie	0 GVEA Backdoor
Jan-06	25	3	5	5	5	7	0
Feb-06	25	3	5	5	5	7	0
Mar-06	25	3	5	5	5	7	0
Apr-06	25	3	5	5	5	7	0
May-06	20	3		5	5	7	0
Jun-06	20	3		5	5	7	0
Jul-06	20	3		5	5	7	0
Aug-06	20	3		5	5	7	0
Sep-06	20	3		5	5	7	0
Oct-06	20	3		5	5	7	0
Nov-06	20	3	5		5	7	0
Dec-06	20	3	5		5	7	0
Jan-07	20	3	5		5	7	0
Feb-07	20	3	5		5	7	0
Mar-07	20	3	5		5	7	0
Apr-07	20	3	5	5		7	0
May-07	20	3	5	5		7	0
Jun-07	20	3	5	5		7	0
Jul-07	20	3	5	5		7	0
Aug-07	20	3	5	5		7	0
Sep-07	25	3	5	5	5	7	0
Oct-07	25	3	5	5	5	7	0
Nov-07	25	3	5	5	5	7	0
Dec-07	25	3	5	5	5	7	0
Jan-08	25	3	5	5	5	7	0
Feb-08	25	3	5	5	5	7	0
Mar-08	25	3	5	5	5	7	0
Apr-08	25	3	5	5	5	7	0
May-08	25	3	5	5	5	7	0
Jun-08	25	3	5	5	5	7	0
Jul-08	25	3	5	5	5	7	0
Aug-08	25	3	5	5	5	7	0
Sep-08	25	3	5	5	5	7	0
Oct-08	25	3	5	5	5	7	0
Nov-08	25	3	5	5	5	7	0
Dec-08	25	3	5	5	5	7	0

Table 18. Nameplate scenario—maximum electric supply and peak demand (MW).

Month	Demand MW	Supply						
		Total	3 Turbine #1	5 Turbine #3	5 Turbine #4	5 Turbine #5	7 GVEA Intertie	5 GVEA Backdoor
Jan-06	20.5	30	3	5	5	5	7	5
Feb-06	19.2	30	3	5	5	5	7	5
Mar-06	19.1	30	3	5	5	5	7	5
Apr-06	16.0	30	3	5	5	5	7	5
May-06	16.6	25	3		5	5	7	5
Jun-06	17.4	25	3		5	5	7	5
Jul-06	17.7	25	3		5	5	7	5
Aug-06	18.1	25	3		5	5	7	5
Sep-06	19.0	25	3		5	5	7	5
Oct-06	19.9	25	3		5	5	7	5
Nov-06	23.5	25	3	5		5	7	5
Dec-06	25.3	25	3	5		5	7	5
Jan-07	25.3	25	3	5		5	7	5
Feb-07	23.8	25	3	5		5	7	5
Mar-07	23.6	25	3	5		5	7	5
Apr-07	19.5	25	3	5	5		7	5
May-07	17.5	25	3	5	5		7	5
Jun-07	18.3	25	3	5	5		7	5
Jul-07	18.6	25	3	5	5		7	5
Aug-07	19.4	25	3	5	5		7	5
Sep-07	20.0	30	3	5	5	5	7	5
Oct-07	20.9	30	3	5	5	5	7	5
Nov-07	24.6	30	3	5	5	5	7	5
Dec-07	26.6	30	3	5	5	5	7	5
Jan-08	26.5	30	3	5	5	5	7	5
Feb-08	25.0	30	3	5	5	5	7	5
Mar-08	24.8	30	3	5	5	5	7	5
Apr-08	20.5	30	3	5	5	5	7	5
May-08	18.7	30	3	5	5	5	7	5
Jun-08	18.8	30	3	5	5	5	7	5
Jul-08	19.1	30	3	5	5	5	7	5
Aug-08	19.1	30	3	5	5	5	7	5
Sep-08	19.6	30	3	5	5	5	7	5
Oct-08	20.5	30	3	5	5	5	7	5
Nov-08	24.1	30	3	5	5	5	7	5
Dec-08	26.0	30	3	5	5	5	7	5

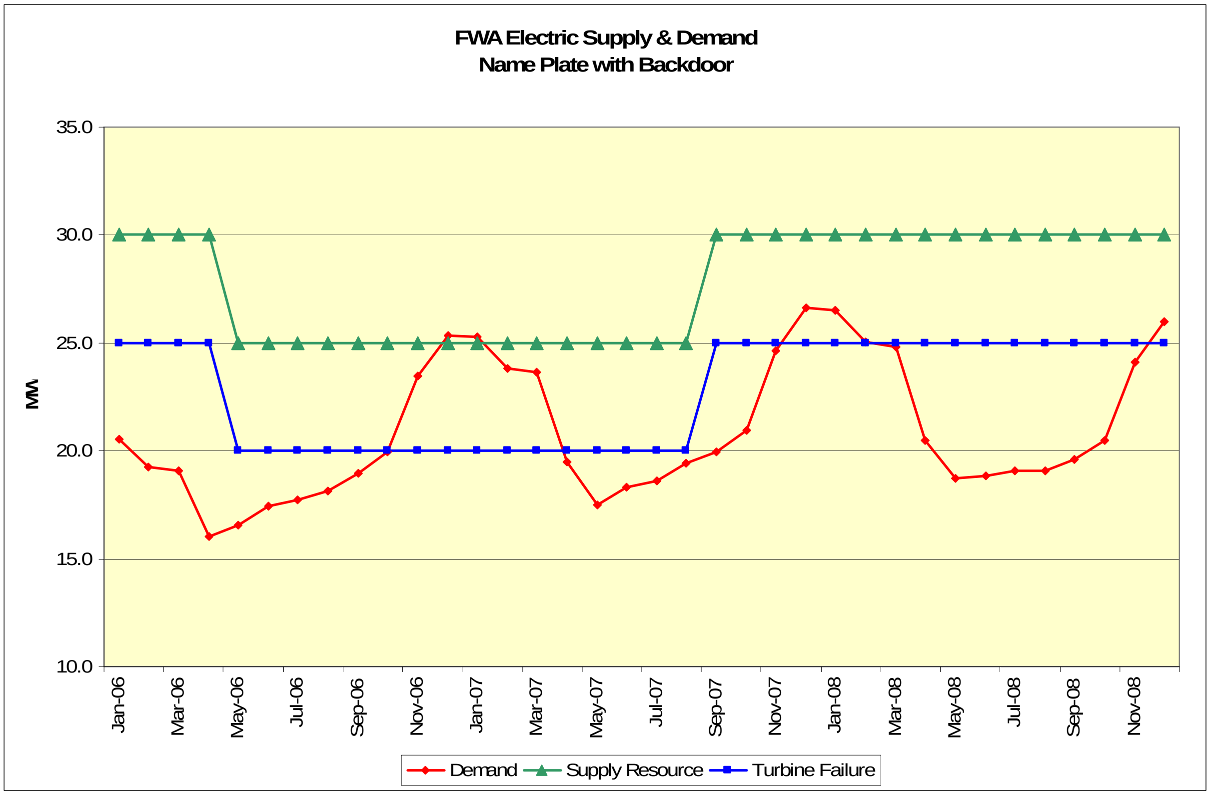

Figure 19. Nameplate scenario—supply and demand.

3.4.3 Five-quarter STG operation scenario

Under this scenario, each STG is operated at approximately 125 percent of its nominal design rating, and the GVEA backdoor intertie is used. This results in a maximum supply of 34.75 MW, of which 28.5 MW would be available during the winter of 2006/2007 (Table 19). While this is adequate to meet the load, if one of the two remaining large STGs should fail, the available supply would only be 22.25 MW (see). This represents about a 3 MW power shortfall. Furthermore, it is uncertain how long the STGs can be operated at a 5/4 capacity, or how reliable this operational mode will be.

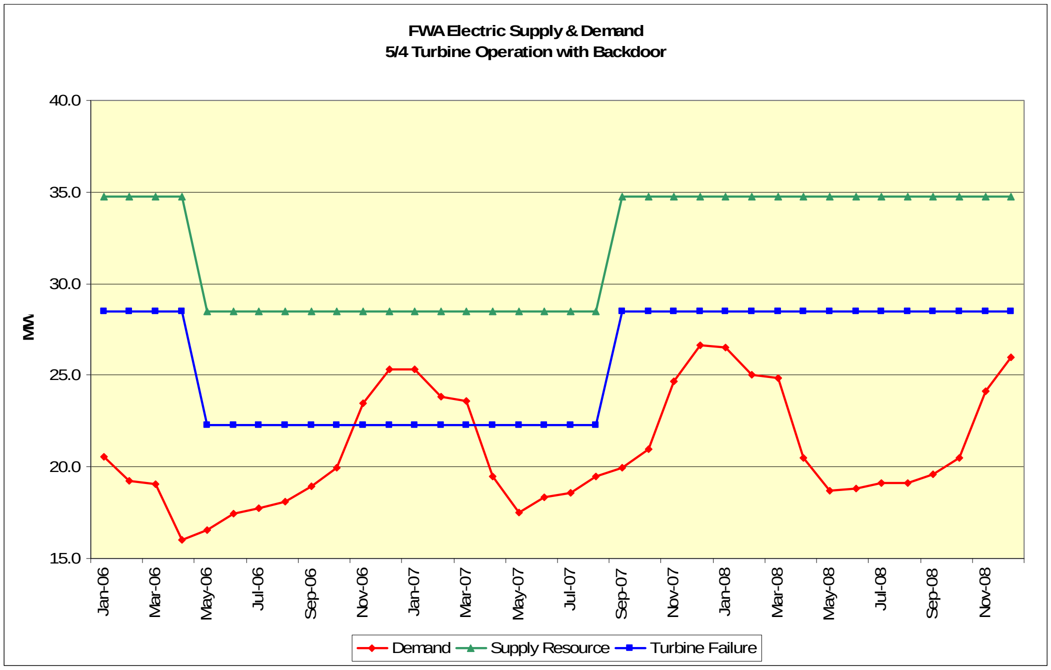

Figure 20. Five quarter STG operation scenario—supply and demand.

Table 19. Five quarter scenario—maximum electric supply and peak demand (MW).

Month	Demand MW	Supply						
		Total	4 Turbine #1	6.25 Turbine #3	6.25 Turbine #4	6.25 Turbine #5	7 GVEA Intertie	5 GVEA Backdoor
Jan-06	20.5	34.75	4	6.25	6.25	6.25	7	5
Feb-06	19.2	34.75	4	6.25	6.25	6.25	7	5
Mar-06	19.1	34.75	4	6.25	6.25	6.25	7	5
Apr-06	16.0	34.75	4	6.25	6.25	6.25	7	5
May-06	16.6	28.5	4		6.25	6.25	7	5
Jun-06	17.4	28.5	4		6.25	6.25	7	5
Jul-06	17.7	28.5	4		6.25	6.25	7	5
Aug-06	18.1	28.5	4		6.25	6.25	7	5
Sep-06	19.0	28.5	4		6.25	6.25	7	5
Oct-06	19.9	28.5	4		6.25	6.25	7	5
Nov-06	23.5	28.5	4	6.25		6.25	7	5
Dec-06	25.3	28.5	4	6.25		6.25	7	5
Jan-07	25.3	28.5	4	6.25		6.25	7	5
Feb-07	23.8	28.5	4	6.25		6.25	7	5
Mar-07	23.6	28.5	4	6.25		6.25	7	5
Apr-07	19.5	28.5	4	6.25	6.25		7	5
May-07	17.5	28.5	4	6.25	6.25		7	5
Jun-07	18.3	28.5	4	6.25	6.25		7	5
Jul-07	18.6	28.5	4	6.25	6.25		7	5
Aug-07	19.4	28.5	4	6.25	6.25		7	5
Sep-07	20.0	34.75	4	6.25	6.25	6.25	7	5
Oct-07	20.9	34.75	4	6.25	6.25	6.25	7	5
Nov-07	24.6	34.75	4	6.25	6.25	6.25	7	5
Dec-07	26.6	34.75	4	6.25	6.25	6.25	7	5
Jan-08	26.5	34.75	4	6.25	6.25	6.25	7	5
Feb-08	25.0	34.75	4	6.25	6.25	6.25	7	5
Mar-08	24.8	34.75	4	6.25	6.25	6.25	7	5
Apr-08	20.5	34.75	4	6.25	6.25	6.25	7	5
May-08	18.7	34.75	4	6.25	6.25	6.25	7	5
Jun-08	18.8	34.75	4	6.25	6.25	6.25	7	5
Jul-08	19.1	34.75	4	6.25	6.25	6.25	7	5
Aug-08	19.1	34.75	4	6.25	6.25	6.25	7	5
Sep-08	19.6	34.75	4	6.25	6.25	6.25	7	5
Oct-08	20.5	34.75	4	6.25	6.25	6.25	7	5
Nov-08	24.1	34.75	4	6.25	6.25	6.25	7	5
Dec-08	26.0	34.75	4	6.25	6.25	6.25	7	5

3.4.4 Five quarter STG operation and temperature based transformer loading scenario

Under this scenario, each STG is operated at approximately 125 percent of its nominal design rating, the GVEA backdoor intertie is used, and approximately 10 MW of power is obtained through the intertie. The ability of the nominal 7.5 MVA transformer to provide 10–11 MVA (8.5–10 MW depending on power factor and temperature assumptions), takes advantage of its improved throughput at winter temperatures. This scenario results in a maximum supply of 37.75 MW, of which 31.5 MW would be available during the winter of 2006/2007 (Table 20). While this is adequate to meet the load, if one of the two remaining large STGs should fail, the available supply would only be 25.25 MW (see Figure 21) or about equal to the 25.3 MW demand forecast for the winter of 2005/2006. Given the uncertainties of: (1) how long the STGs can be operated at a 5/4 capacity, (2) the reliability of this operational mode, and (3) the demand projections, this scenario still provides no reserve power margin.

Table 20. Five quarter STG operation and temperature based transformer loading scenario.

Month	Demand MW	Supply						
		Total	4 Turbine #1	6.25 Turbine #3	6.25 Turbine #4	6.25 Turbine #5	10 GVEA Intertie	5 GVEA Backdoor
Jan-06	20.5	37.75	4	6.25	6.25	6.25	10	5
Feb-06	19.2	37.75	4	6.25	6.25	6.25	10	5
Mar-06	19.1	37.75	4	6.25	6.25	6.25	10	5
Apr-06	16.0	34.75	4	6.25	6.25	6.25	7	5
May-06	16.6	28.5	4		6.25	6.25	7	5
Jun-06	17.4	28.5	4		6.25	6.25	7	5
Jul-06	17.7	28.5	4		6.25	6.25	7	5
Aug-06	18.1	28.5	4		6.25	6.25	7	5
Sep-06	19.0	28.5	4		6.25	6.25	7	5
Oct-06	19.9	31.5	4		6.25	6.25	10	5
Nov-06	23.5	31.5	4	6.25		6.25	10	5
Dec-06	25.3	31.5	4	6.25		6.25	10	5
Jan-07	25.3	31.5	4	6.25		6.25	10	5
Feb-07	23.8	31.5	4	6.25		6.25	10	5
Mar-07	23.6	31.5	4	6.25		6.25	10	5
Apr-07	19.5	28.5	4	6.25	6.25		7	5
May-07	17.5	28.5	4	6.25	6.25		7	5
Jun-07	18.3	28.5	4	6.25	6.25		7	5
Jul-07	18.6	28.5	4	6.25	6.25		7	5
Aug-07	19.4	28.5	4	6.25	6.25		7	5
Sep-07	20.0	34.75	4	6.25	6.25	6.25	7	5
Oct-07	20.9	37.75	4	6.25	6.25	6.25	10	5
Nov-07	24.6	37.75	4	6.25	6.25	6.25	10	5
Dec-07	26.6	37.75	4	6.25	6.25	6.25	10	5
Jan-08	26.5	37.75	4	6.25	6.25	6.25	10	5
Feb-08	25.0	37.75	4	6.25	6.25	6.25	10	5
Mar-08	24.8	37.75	4	6.25	6.25	6.25	10	5
Apr-08	20.5	34.75	4	6.25	6.25	6.25	7	5
May-08	18.7	34.75	4	6.25	6.25	6.25	7	5
Jun-08	18.8	34.75	4	6.25	6.25	6.25	7	5
Jul-08	19.1	34.75	4	6.25	6.25	6.25	7	5
Aug-08	19.1	34.75	4	6.25	6.25	6.25	7	5
Sep-08	19.6	34.75	4	6.25	6.25	6.25	7	5
Oct-08	20.5	37.75	4	6.25	6.25	6.25	10	5
Nov-08	24.1	37.75	4	6.25	6.25	6.25	10	5
Dec-08	26.0	37.75	4	6.25	6.25	6.25	10	5

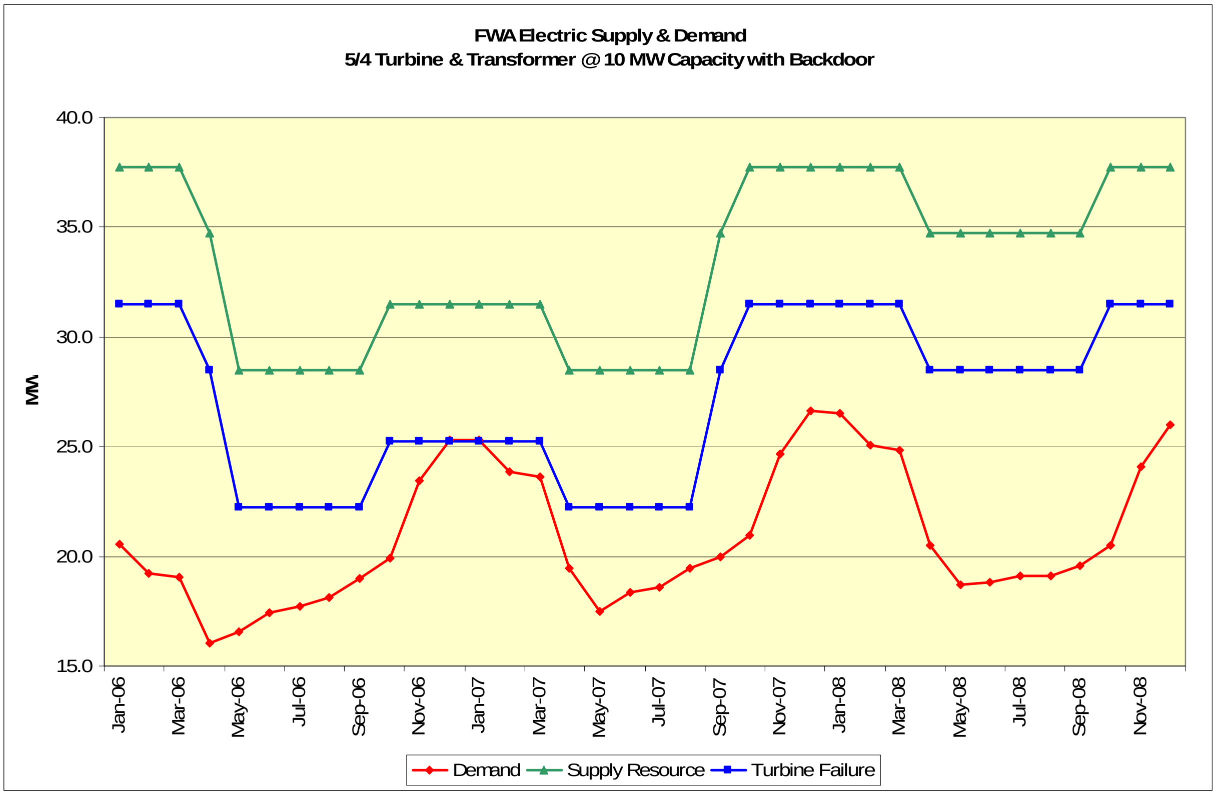

Figure 21. Five quarter STG operation and temperature based transformer loading scenario—supply and demand.

3.4.2 Net power shortfall

Based on the above scenarios, there is a need to supplement the existing power available to the FWA to meet the forecast winter 2006/2007 electric power demand. The net power shortfall ranges from 0–10.3 MW depending on the scenario. *For planning purposes the net power shortfall is estimated to be 2.3–3.8 MW*. This assumes use of the GVEA backdoor intertie (5 MW) and the temperature dependent load capabilities of the main intertie transformer (8.5–10 MW), and the availability of one 5 MW STG and the 3-MW STG. This does not assume operating the STGs at 5/4 capacity.

3.5 FWA electric power requirement estimates—short-term

Beyond October 2007, with the completion of the ACC project, the CHPP will regain the capability to operate up to four of its STGs. However, with the projected growth in electric power demand, there will be an increasing net power shortfall over time. Figure 22 shows the demand growth in comparison to FWA supply, assuming no additional CHPP capacity is provided, and no increase in the transformer capacity of the existing GVEA intertie. The horizontal lines indicate several supply scenarios representing different operational or availability conditions.

3.5.1. Baseline supply scenario

The basic scenario corresponds to a CHPP output of 18 MW plus the nominal 7 MW GVEA import capability (25-MW total). Under this operating scenario, the net power shortfall ranges from 1.6 MW in 2007 to 4.3 MW in 2011 to 7.7 MW in 2020.

3.5.1. Baseline supply and temperature based transformer loading

This scenario corresponds to a CHPP output of 18 MW plus 10 MW GVEA transformer capability (28-MW total). The higher transformer output as compared to the nominal case, results from its higher loading capability at colder temperatures. Under this operating scenario, the year 2007 loads are met, with a reserve margin of 1.4 MW. However, by the year 2011, there is net power shortfall of 1.3 MW increasing to 4.7 MW in 2020.

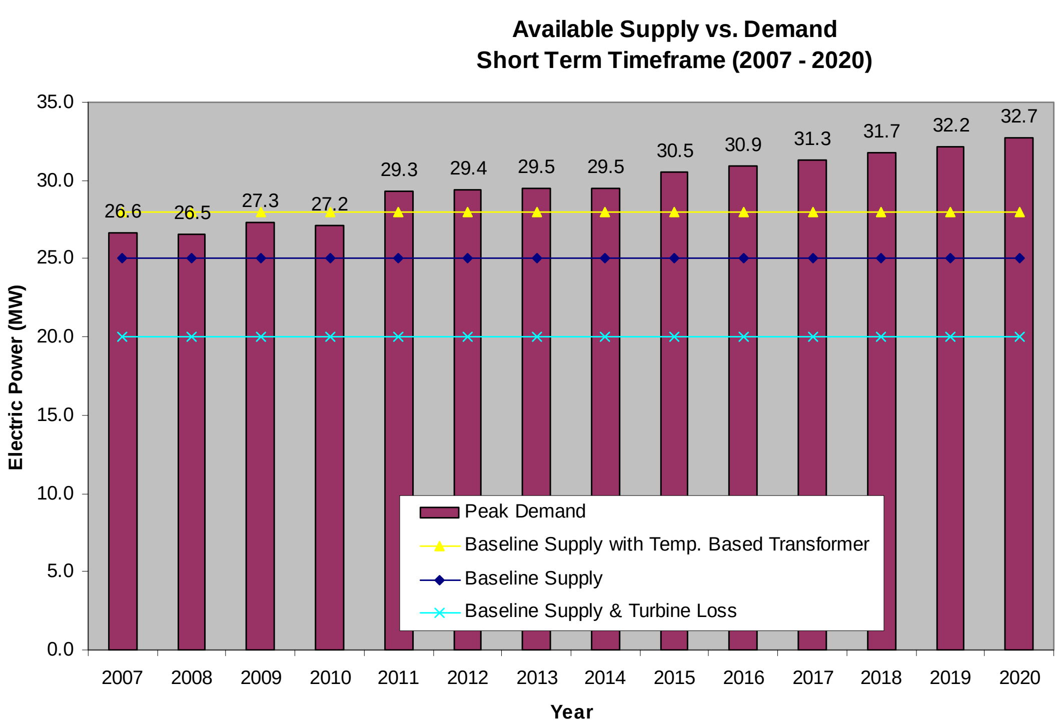

Figure 22. Available supply vs. demand—short term.

<u>Baseline Supply and Turbine Loss</u>. This scenario assumes that there is a loss of one STG during the peak demand period, reducing the CHPP output to 13 MW. The transformer operates at its nominal 7 MW capacity, which brings the total supply to 20 MW. Under this operating scenario, the net power shortfall ranges from 6.6 MW in 2007 to 9.3 MW in 2011, to 12.7 MW in 2020.

The scenarios vary significantly with regard to the potential net power shortfall. Given the importance of having sufficient power even if unforeseen events occur, it is suggested that the planning number assume a turbine loss scenario. **Therefore, for planning purposes the net shortage is estimated to range from 3.6–5.1 MW in 2007, increasing to 6.3–7.8 MW in 2011 and 9.7–11.2 MW in 2020.** This assumes use of the temperature based transformer loading (8.5–10 MW winter potential vs. 7 MW nominal rating), no backdoor intertie, and no 5/4 STG operation.

4 Condition Assessment of the CHPP Electrical Systems

4.1 Introduction

The CHPP electrical system includes 12.47 kV switchgear, 4160V switchgear, 2400V switchgear, 2400V motor control centers, the 480V system, 120V system, 125VDC system, and a back up diesel generator for lighting. The CHPP transformer yard connects the CHPP's electrical system to Fort Wainwright's 12.47 kV Distribution System and the GVEA system.

Fort Wainwright's existing 12.47 kV distribution system consists primarily of overhead pole lines and is connected to the CHPP's 12.47kV switchgear. The CHPP is also connected to the GVEA system through the 12.47kV switchgear. The CHPP's electrical generators are connected to the 12.47 kV switchgear, and the new ACC is connected to the 12.47 kV switchgear. The Fort Wainwright electrical distribution system cannot be used without the 12.47kV switchgear in service, regardless of the status of the generators or the GVEA system. The 12.47kV switchgear is critical to the Base operation; as a result, this condition assessment focused on the 12.47 kV switchgear. The GVEA transformer is critical for the connection to the GVEA electrical system. The condition of the GVEA transformer will be determined by GVEA. Note that, as part of the team, the U.S. Army Corps of Engineers, Engineering and Support Center, Huntsville (CEHNC) also briefly surveyed other areas of the electrical system (see Appendix C).

4.2 12.47 kV Switchgear assessment

The CHPP 12.47 kV electrical system consists of 15 kV class metal-clad switchgear and cable connecting the switchgear to the transformers in the switchyard, the Base overhead distribution system and generators 1, 3, 4, and 5. The switchgear is arranged in two busses (Bus 1 and Bus 2) tied together with a tie breaker. The loads designated as "Feeders" are ties to the Base overhead distribution system. The remaining loads are connected to CHPP equipment and transformers. A new section has been added at the ends of Bus 1 and Bus 2 for the ACC (Figure 23).

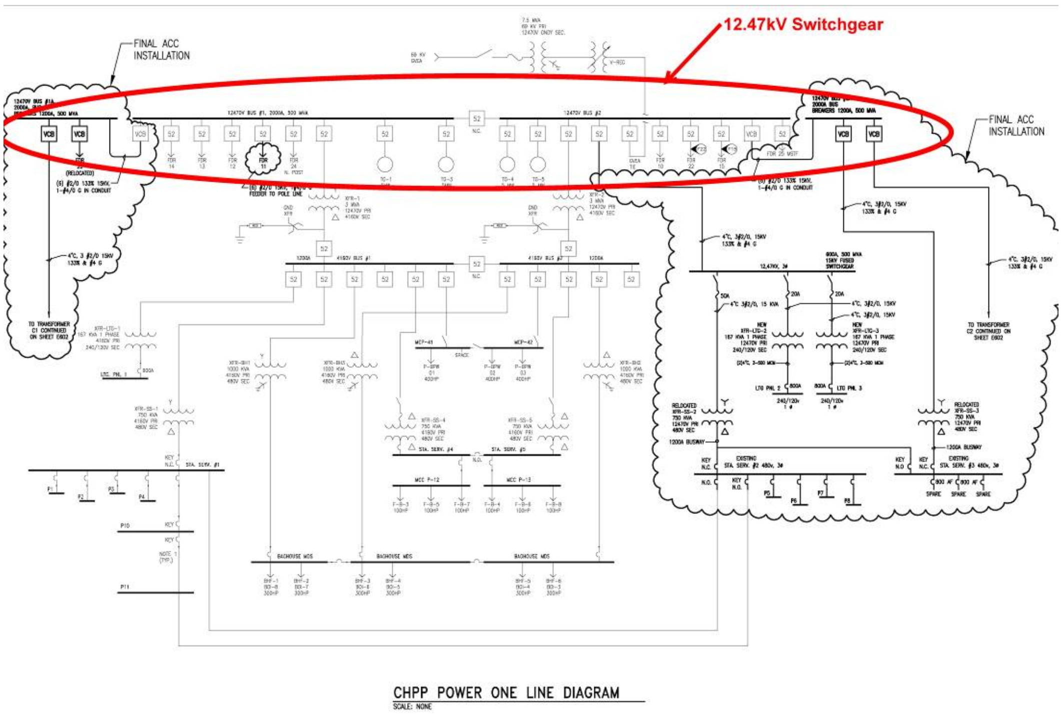

Figure 23. CHPP one-line diagram.

The 12.47 kV switchgear was installed in the mid 1950s. The switchgear breakers were installed with the switchgear and not replaced unless they failed. There is no record of preventative maintenance activities for the 12.47 kV switchgear. The structure of metal clad switchgear includes the electrical bus work, bus insulators, control wiring, current transformers, and potential transformers. Part of the structure also includes the protective relays, meters, control switches, and indicating lights. The bus insulators' insulating capability deteriorates with age and the bus works' mechanical integrity. As a result, the electrical characteristics deteriorate with age. The insulation on the control wiring ages, dries out, and loses some of its insulating capabilities. Dust and foreign substances can build up between control circuit contacts. Consequently, the overall equipment capability deteriorates over time. An accurate assessment of the existing capability can only be determined by internal tests and inspection.

There are no recorded maintenance records for the medium voltage breakers. Medium voltage breakers are not designed to operate reliably for decades without maintenance. At some point, the breakers will fail to operate. The failures will most likely occur when the breaker is under heavy load or when a fault occurs. Breaker failure poses a risk for plant operation, plant safety, and personnel safety.

4.2.1 Assessment summary immediate

The 12.47 kV switchgear should be inspected and refurbished to provide some degree of assurance that the equipment will continue to operate. Each section in the structure should have the bus compartment and control components inspected and refurbished as required. The incoming cable compartments should be inspected, both visually and using infrared temperature detectors. The breakers should be inspected and refurbished as required. Sections of the equipment may require de-energization for testing. Considering the critical role of the switchgear and the time frame, the efforts should start as soon as possible. The CEHNC report (Appendix C) includes a list of recommended tasks and cost estimate details.

4.2.2 Assessment summary short-term

The short-term solutions require an increase in the capacity of the 12.47 kV equipment, increased reliability, and increased control of the CHPP resources. The CHPP personnel have (in difficult conditions and over an extended period of time) performed a difficult task remarkably well. They have provided valuable input, noted in Sections 1.3.1 and 6.3.9 and have even made modifications to the existing switchgear to support the ACC Project. However the existing 12.47 kV switchgear should be replaced with new switchgear to provide increased safety, increased reliability, and increased capacity to meet future Fort Wainwright requirements.

4.3 Cost estimate to repair/replace 12.47 kV switchgear

As mentioned above, it is recommended that the existing switchgear be replaced. Table 21 lists a cost estimate of this option. Figure 23 shows a one-line diagram for the equipment to be replaced. Note that the CEHNC estimate for this work including a new control room is about $21.6 million (see Appendix C). However, the CEHNC estimate contains a number of other items in addition to the switchgear estimate.

Table 21. Switchgear replacement costs.

Description	Qty (Ea)	Unit Cost	Total Cost	Comments
Demo existing 12.47KV switchgear, assume 26 vertical sections	1	$68,640	$68,640	1
Remove existing 15KV cable	10,000	$9	$92,400	2
Install new MV cable	13,000	$15	$197,340	
New 12.47KV switchgear, assume 36 vertical sections	1	$1,512,000	$1,512,000	
Install new 12.47KV switchgear	1	$190,080	$190,080	
Subtotal			$2,060,460	
Allowance for engineering and CM (~10%)			$206,000	
Contingency (~10%)			$227,000	
Total			$2,593,460	

Notes/Basis:

1. The estimate does not include costs that may be associated with environmental considerations for disposal or control of the items removed. The ACC switchgear sections are not included.
2. The estimate is based on typical cable lengths and sizes, and, does not include control or instrumentation cable. The MV cable demo/installation costs can be a significant component of the total costs depending on its length. The switchgear does not have to be installed in the same place and could be installed as described in Section 6.3.5.
3. The costs major capital equipment costs and not based on quotes or detailed Scopes that would include engineering services or construction management, they are ±30%.

4.4 Assessment of other areas

While the switchgear is the most critical element directly related to the distribution of power from the CHPP as well as from the GVEA intertie, other areas were briefly surveyed by team members from CEHNC. Table 22 lists the recommended upgrades and cost estimates developed by CEHNC for a number of systems (see Appendix C for details).

Table 22. FWA electrical system upgrade costs.

Task	Estimated Cost
Replace airfield lighting	$13,928,408
Replace overhead electrical distribution	$16,066,718
Replace underground electrical distribution	$3,336,245
Replace street lighting	$2,550,957
Install generators and switchgear (black start)	$9,407,511

Note that, except for the black start generators, which are intended to re-start the CHPP after an outage, the options are not directly related to the CHPP.

5 Capability of Electric Utilities To Meet FWA Year 2020 Demand

5.1 Introduction

This chapter reviews the capability of GVEA and other utilities to meet FWA's forecast demand in the year 2020. As discussed in Chapter 2, FWA will require an estimated 32.7 MW of electric power to meet its full requirements. Assuming the CHPP continues to operate at its current "nameplate" capacity, the incremental requirement (power needed from other generation sources) is estimated to be 14.7–19.7 MW. The latter figure assumes an unanticipated outage of one 5-MW STG, while the smaller figure assumes all the STGs are operational (18 MW total output).

5.2 GVEA power generation capacity

GVEA's currently owned generating capacity of about 288 MW is supplied by six generating facilities. This generating capacity can vary somewhat by season, since the combustion turbines can increase their generating capacity in the winter. Table 23 lists the facilities with their available capacities.

Table 23. GVEA generation capacity.

Name of Power Plant	Plant Type	Capacity (MW)
Delta Power Plant (formerly named Chena 6), Fairbanks	Oil-fired combustion turbine	27
Zhender Facility, Fairbanks	Oil fired combustion turbines and diesel engines	36
North Pole Power Plant, North Pole	Oil-fired combustion turbines	120
North Pole Expansion (NPE), North Pole (planned September 2006 start-up)	Oil-fired/Naphtha combined cycle combustion turbine and steam turbine	60
Healy Power Plant, Healy	Coal-fired boiler/steam turbine	25
Bradley Lake Hydroelectric Plant, Homer	Hydro turbine	20
Total		*288*

Additional generation capacity of about 22 MW is available from the coal-fired Chena Power Plant that is located in Fairbanks and owned and operated by Aurora Energy, LLC. GVEA purchases all of the electricity generated by this plant. With the inclusion of the Chena plant, GVEA's currently available generating capacity is approximately 310 MW.

Note that the GVEA NPE has been configured to enable future installation of another 60 MW of capacity when needed. GVEA also plans to increase its use of renewable energy to meet its peak demands. It has adopted a Renewable Portfolio Standard (RPS) to meet 10 percent of its peak load from renewable energy by 2007 and 20 percent by 2014.

GVEA currently relies on its most economical generation source in Healy, and purchases from Aurora Energy in Fairbanks, Anchorage-located utilities and Bradley Lake for much of its electricity requirements. The oil-fired generation units in Fairbanks and North Pole are generally used as supplemental power during peak loads or when there is a problem with the line between Healy and Fairbanks. The amount of power GVEA can receive from the more economical generation sources in south central Alaska is restricted by the transmission capacity of the intertie between Anchorage and Fairbanks. The Wasilla to Healy or southern intertie enables GVEA to import about 70 MW from the Anchorage area. This includes the 20 MW from the Bradley Lake hydro plant plus additional power from Chugach Electric and Matanuska Light and Power (ML&P) totaling about 50 MW (about two-thirds from Chugach and one-third from ML&P). The Northern Intertie between Healy and Fairbanks enables the power from the 20 MW Healy plant plus the power from the south central region to serve Fairbanks. The addition of a second, parallel line (230 kV), between Healy and Fairbanks has added to the reliability of the system. The lines are capable of carrying 140 MW although generally transfer no more than 100 MW (the maximum power from the Healy Plant plus the power coming from the southern intertie).

5.3 Power generation from other sources

Other than the GVEA-owned plants and Aurora there are no commercial sources of power in the greater Fairbanks area. The University of Alaska has its own central plant and Eielson AFB has its own central plant, as well. The Eielson plant has spare capacity at this time (several MW), but it is not clear how much of this capacity will be available in the future. This should be examined to see if there are any economic benefits for purchase of this power relative to other GVEA sources.

Ample generating capability exists in the Anchorage area and the south central region. As discussed previously, the limitation for importing to the Fairbanks area is the capacity of the interties. Clear Air Force Base generates all its own power and also has excess capacity. However, it is not connected to the grid, and a dedicated power line would have to be installed between the base and FWA to make use of this extra capacity. The estimated cost for such a line would be approximately $32 million.

5.4 GVEA current and projected peak demand and capacity for meeting FWA's needs

GVEA's peak demand in 2005 was 194.7 MW and is projected to reach 230 MW by 2007. The bulk of this load growth is a result of power demands from the Ground-Based Missile Defense system, Pogo Gold Mine, and Alyeska Pump Station #9. The NPE was constructed to help meet these and future loads. Excluding any additional loads from FWA, this means the utility is projected to have about 58 MW of extra capacity in 2007. Currently (2006), the spare capacity (exclusive of the 30 percent reserve margin that must be maintained) is about 28–36 MW according to GVEA (information provided by M. Wright to Ken Hudson via telecon).

While GVEA expansion plans for the year 2020 are not known, it is assumed that the utility will add capacity as required by its customers, including FWA, sufficient to meet the demands plus the 30 percent reserve margin. This would also include upgrading the 69 kV transmission line from the utility to FWA, which is currently limited to 30 MW.

6 Electric Capacity Shortage Alternatives

6.1 Introduction

This chapter identifies alternatives to meet the electrical capacity shortage through FY20, screens out alternatives that are not feasible, and characterizes the remaining alternatives by technical features, advantages, disadvantages, and (where applicable) cost.

For the purposes of this review, the capacity shortage alternatives have been grouped according to the when the solutions can be implemented. This logic was chosen because of the urgent solutions of the immediate problem are likely to involve temporary measures. The more permanent solutions are likely to need more time for proper planning, design, and appropriations. The data in Table 24 describe these groupings.

Note that only the immediate and short-term options are evaluated by this effort. The identification of potential alternatives began in late April, days after this study was initiated. Several options were subsequently dismissed as being not feasible either because they could not be implemented within the required time frame, or they could not be counted on with the necessary assurance to be available when needed (they are not “firm”). The remaining options have been investigated further in the following sections.

6.2 Immediate capacity shortage options

Tables 25 and 26 list the options that were considered for solving the immediate capacity shortage options faced by FWA. The following section characterizes the feasible options in terms of key characteristics.

Table 24. Electric capacity alternative timeframe groupings.

Alternatives Grouping	Operation by	Appropriation Cycle	Notes
Immediate	Winter 2006/07	Immediate	Must solve shortage until short-term solution
Short-Term	Winter 2011	FY 2008-2011	The demand is anticipated to jump up in 2012
Long-Term	FY 2020	As required	This is outside the scope of this evaluation

Table 25. Immediate capacity shortage options—feasible.

No.	Description
1	Additional 7.5 MVA GVEA Transformer
2	Increase 7.5 MVA Intertie Capacity
3	GVEA Backdoor Intertie for Housing Units
4	“Prime Power” Diesel Generator Rental
5	Commercial Diesel Generator Rental
6	Shorten ACC Downtime for each STG
7	Delay the ACC Connection
8	Use Steam Turbines at “5/4” Capacity

Table 26. Immediate capacity shortage options—not feasible.

No.	Description	Notes on Feasibility
1	Elmendorf generators (2 @ 0.835 MW each)	Currently Unavailable
2	GVEA mobile generators (2 @ 2.5 MW each)	Not Firm. Can be withdrawn by GVEA at any time
3	GVEA portable substation (10 MW)	Not Firm
4	Operational changes to increase STG-1 from 3 to 5 MW	Would require increasing the 10 psig steam pressure use. Unlikely to implement within the 5 months available.
5	Load shedding and use backup power	Since the outage could easily extend past 7 days, this alternative was considered “not acceptable.” By ignoring the ability to shed load, and degree of conservatism is introduced into the selected alternative(s).
6	Install new transformer	The lead time for this requisition is about 50 weeks.
7	Install new diesel generator	The lead time for this requisition is about 50 weeks.

6.2.1 Immediate option 1: additional 7.5 MVA GVEA transformer

An additional transformer could be installed to enable increased power to be purchased from GVEA. GVEA has indicated that they have a suitable transformer available (used 7.5 MVA model), and, that they have the ability to install the transformer and the required switching equipment by October 2006. This option is being pursued.

GVEA has stated that this intertie would be a temporary intertie for the following reasons:

- The transformer will be installed on a temporary pad to expedite the construction schedule.

- The connections to the transformer may be made with overhead conductors as opposed to bus work to expedite the installation.
- The degree of control and protection may be less than that normally applied.
- Note that there is not a concern as to the capability or adequacy of the proposed installation. However the installation will not include features that provide GVEA with the control, flexibility, and life time expected for normal utility grade construction.
- The additional transformer needs to be connected to Fort Wainwright's 12.47 kV distribution system, which could be accomplished in different ways.
- Make connections from new switching equipment near the new transformer to the areas at Fort Wainwright that require the power.
- Add and modify the switching arrangement of the over head lines near the CHPP to connect to the 12.47 kV "Feeders."
- Modify the existing 12.47 kV switchgear to accept an additional incoming feeder supply.
- It has been decided to connect the supply from the 7.5 MVA GVEA transformer to the existing CHPP 12.47 kV Switchgear.
- The new transformer size was determined by existing GVEA transformers available for immediate use. In addition, GVEA has notified Fort Wainwright that GVEA will inspect the existing transformer to provide some assurance that the transformer is in good condition.

Commercial discussions are currently in progress between Fort Wainwright and GVEA for providing the 7.5 MVA transformer and providing a connection to the Base. The data in Table 27 provide a cost estimate, assuming that Fort Wainwright were to purchase the equipment, including costs* for the typical type of equipment used to connect the transformer and the transformer cost, and is based on connection option no. 1 (Figure 24). Connection option number 2 is likely to be more expensive.

* The development of the installed costs for the additional 7.5 MVA transformer was being developed by GVEA and discussed with contacts representing Fort Wainwright. As such, the development of the same was not an identified task of this study. Nevertheless, costs were developed for reference in case the Base decided to buy the equipment directly.

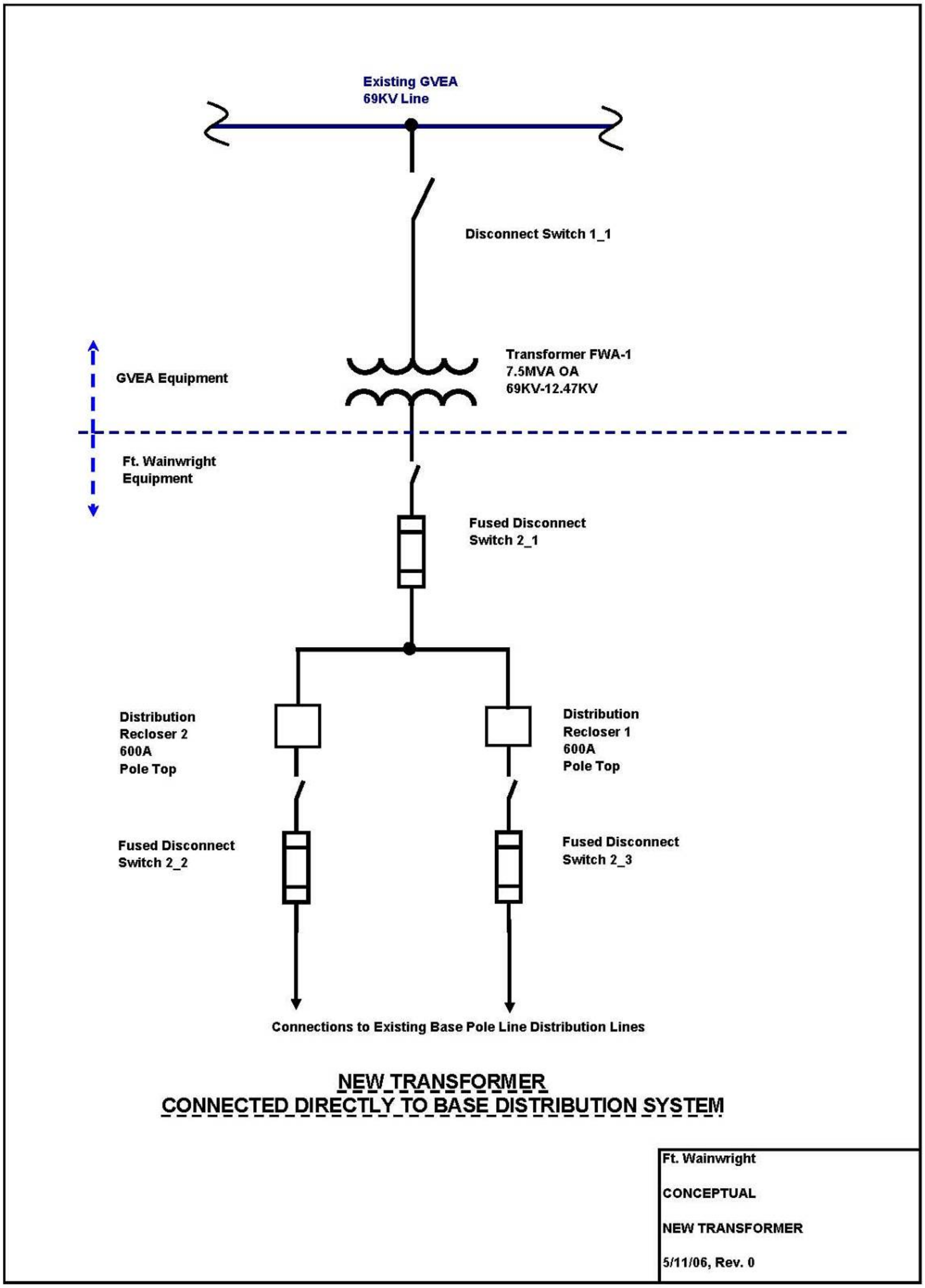

Figure 24. Immediate option 1—new GVEA transformer 1-line diagram.

Table 27. Immediate option 1—new GVEA transformer capital cost estimate.

No.	Description	Rating	Volts	Qty (ea)	Unit Cost	Lead Time (weeks)	Total Cost	Comments
Transformers								
1	7.5MVA oil filled transformer	7.5MVA, OA, 65C	69KV-12.47KV	1	$296,200	50	$296,200	
1a	Transformer foundation			1	$38,080		$38,080	
1b	Transformer grounding			1	$4,168		$4,168	
	15KV substation							
2	Fused disconnect switch (Cut Out)	600-800 A	15KV	1	$20,360	25	$20,360	Distribution Type, Pole mounted
3	Fused disconnect switch (cut out)	200A	15KV	2	$18,660	25	$37,320	Distribution Type, Pole mounted
4	Distribution recloser	600-800A	15KV	2	$4,942	25	$9,884	Similar to ABB Type ESV
5	Lightning arrestor	15KV Class	15KV	6	$1,496	25	$8,976	Distribution Type, Pole mounted
5a	Substation grounding			1	$7,780		$7,780	
5b	Substation control wiring			1	$36,680		$36,680	
Overhead lines								
6	69KV transmission line	336 AL	69KV	1 mile	$398,000		$398,000	
7	12.47KV distribution pole line	1/0	12.47KV	1 mile	$106,000		$106,000	single 3ph ckt, wood construction
	High voltage substation equipment 69KV							
8	High voltage disconnect switches	600-800A	69KV	1	$31,200	40	$31,200	
9	Utility metering			1	$50,560	25	$50,560	
	Subtotal						*$1,045,208*	
	Allowance for engineering and CM (~10%)						$105,000	
	Contingency (~10%)						$115,000	
	Total						*$1,265,208*	

Notes/Basis:

1. The estimate shows the installed major equipment costs for an installation similar to the installation provided by GVEA, it does not include costs that may be associated with environmental considerations for disposal or control of the items removed. The ACC switchgear sections are not included.
2. The estimate is based on typical cable lengths and sizes, and, does not include control or instrumentation cable.
3. The costs are an estimate and not based on quotes or detailed Scopes and are ±30%.

A similar, short term option for a new 10 MVA transformer is discussed in Section 6.3.3.

6.2.2 Immediate option 2: increase 7.5 MVA intertie capacity

Increasing the existing GVEA 7.5MVA intertie to 10MVA is a feasible solution for temperatures of 10 °F or colder. This option has been discussed with GVEA, and is a recommended solution to provide part of the electrical energy shortfall. This option is discussed in more detail in Section 2.3.1. This option will not require a capital investment by the Fort.

6.2.3 Immediate option 3: GVEA Backdoor Intertie for Housing Units

The Back Door intertie is connected to a portion of the Base housing. Connection to the GVEA system requires manual operation, and restoration to the CHPP requires manual switching again. Using the 5 MW maximum capacity of the “Back Door” intertie is a feasible solution and has been discussed with GVEA. This option is discussed in Section 2.3.2. This option will not require a capital investment by the Fort.

6.2.4 Immediate option 4: “prime power” diesel generator rental

This option involves obtaining diesel generators from the 249th Army Engineering Battalion available from Prime Power under the War Reserve/Loan Program. A 4,500 kW unit would be available to meet the requirements. It is estimated that the cost of the unit would be about \$500,000–\$750,000 including shipping, site prep, bill of materials (BOM) (about \$150,000 of the total), operation, and return to the battalion, not including additional fuel storage costs.* An operator would be required to turn on the unit when needed since they have no auto-switching capability. Although, Prime Power has smaller units (1,500 kW Caterpillar generators) that have auto-switching, only one unit is currently available. This would not be of sufficient capacity to meet the potential 3.3 MW power shortfall at FWA, assuming Options 2 and 3 are implemented.

6.2.5 Immediate option 5: commercial diesel generator rental

A commercial diesel generator rental was investigated by contacting NC Power Systems Co., which has a rental fleet of Caterpillar diesel generator sets and a service region of Western Washington, AK, and regions of the Russian Far East (e-mail from Mike J. Wright to Patrick Driscoll 11 May

* Based on one half the estimated price of 2 units, per the e-mail from Major Anthony G. Reed to John R. Lanzarone, 25 May 2006.

2006). NC Power Systems Co offers self-contained, trailerized, sound attenuated generator modules ranging from 30 kW to 2000 kW designed with features suitable for rental applications.

NC Power provided performance and cost information for a 2 MW portable diesel generator with 1250-gal fuel tank. Table 28 lists key design and performance specifications for this proposed unit. Figure 25 shows the diesel generator connection schematic. Additional information can be found in the 12-page Caterpillar specification/brochure (Caterpillar 2000, 2002).

Table 29 lists rental rates that NC Power has provided for the Sound Attenuated Power Module Diesel. Table 30 lists estimated costs for renting two units for 6 months, assuming a total run time of 200 hrs per generator. Note that it is estimated that the units would only need to run about 100 hrs, so this is a conservative assumption. The costs are about $440,000 plus the cost of fuel ($126,000). The two units should provide sufficient capacity to meet the 2.3–3.8 MW net shortfall forecast for the baseline scenario, assuming Options 2 and 3 are implemented. The unit is assumed to not need an SCR for NO_x control in view of the limited operating hours.

The rented diesel generators could be temporarily installed at Fort Wainwright and connected to the 12.47kV distribution system using a transformer as shown in Figure 25. Additional 12.47 kV switching equipment would need to be provided. (Costs for the additional switching equipment is not included in costs for the diesel generator.) If this method is used, further evaluation is required.

The diesel generators could also be connected to the existing CHPP 4.16 kV switchgear. If the 4.16kV switchgear is used, the switchgear capacities require further evaluation. Switching equipment to connect to the 4.16 kV switchgear are included in the switch equipment for the diesel generator. However, if this option is pursued, the switching arrangement requires further evaluation.

Table 28. Immediate option 5 –diesel generator set specifications/performance for the Caterpillar 2000 kW, 2500 kVA, 60 Hz, 1800 rpm, 480 V diesel generator set.

Parameter	Value	Source	Comment
Service Type	Standby	*	
Rating, kWe	2000	**	Assumed to be gross power
Generator rating, kVA	2500	**	At power factor of 0.80
Generator model	SR4B	**	Caterpillar Model No.
Diesel engine type	3516B TA	**	Caterpillar Model No. (4-stroke water cooled, 16 cylinder, 14 to 1 compression
Diesel engine stroke displacement, cu in.	4210	**	Bore–170 mm, stroke–190 mm
Aspiration	T-A	***	Turbo charged–aftercooled
Fuel consumption: 100% load w/fan, gal/h	135.8	**	
Fuel Consumption: 75% load w/fan, gal/h	103.4	**	
Fuel Consumption: 50% load w/fan, gal/h	73.0	**	
Emissions–NO_x, g/bhp-h	< 9.16	**	Not to exceed, on No. 2 fuel oil.
Emissions–CO, g/bhp-h	< 0.20	**	Not to exceed, on No. 2 fuel oil.
Emissions–HC, g/bhp-h	< 0.16	**	Not to exceed, on No. 2 fuel oil.
Emissions–PM, g/bhp-h	< 0.075	**	Not to exceed, on No. 2 fuel oil.
Exhaust gas flow rate, cfm	15,471	**	
Exhaust gas temperature, °F	847	**	
Sound outside of attenuated enclosure, dBA	70	***	At 50 ft
Enclosure dimensions	8 x 40 ft	***	Nominal, not including access
Fuel capacity, gals	1250	***	8 hrs at 60% capacity factor
Approximate dry weight, lb	30,349 72,000 89,000	** *** ***	Genset only Container, Genset, and switchgear. Per above plus undercarriage.
* (NC Power Systems 14 June 2006) ** (Caterpillar 2002) ***(Caterpillar 2000)			

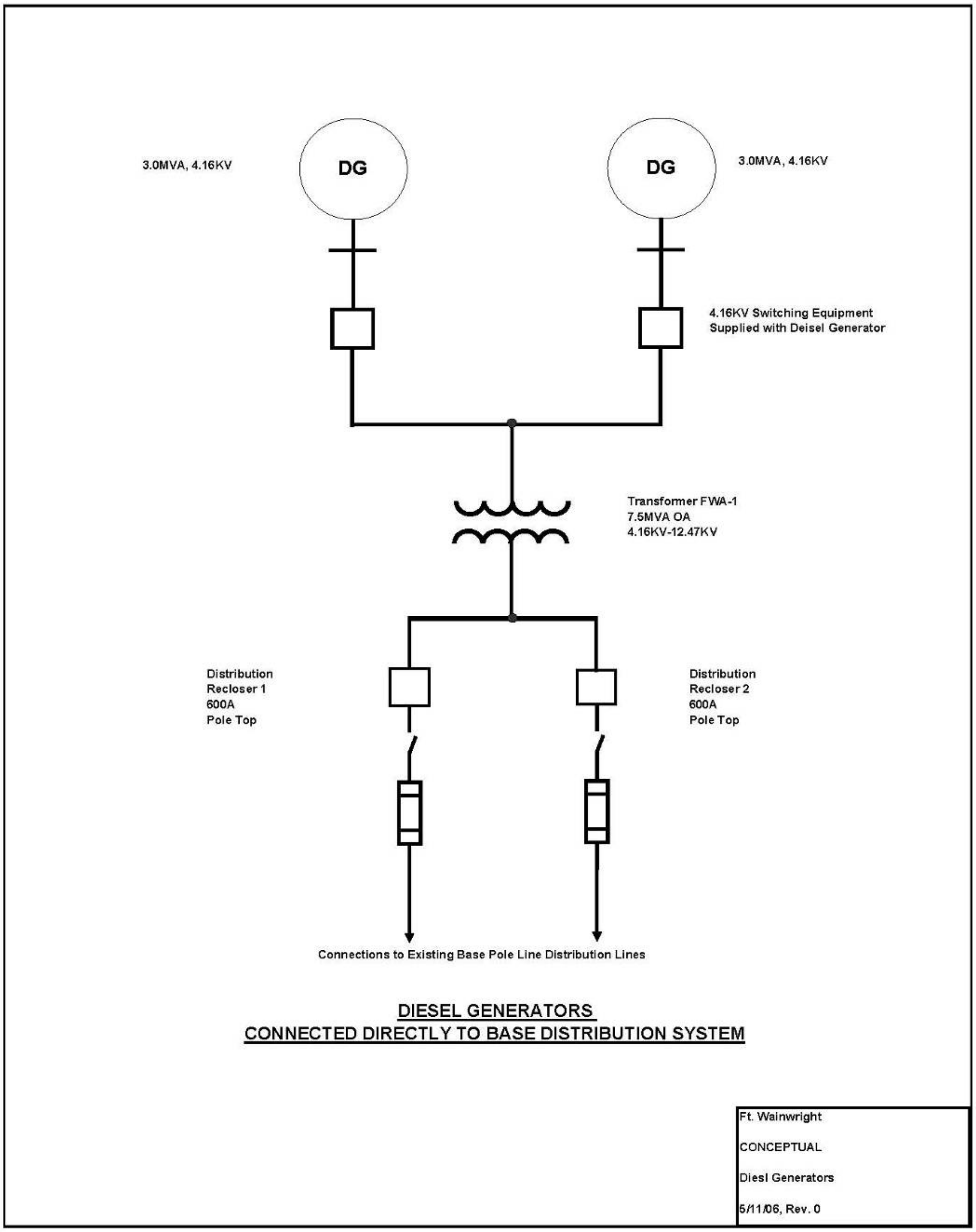

Figure 25. Immediate option 5—commercial diesel generator, 1-line diagram.

Table 29. Immediate option 5 –diesel generator set rental rates for the sound attenuated power module diesel per NC power.

Parameter	Cost	Source	Comment
Rental of XQ2000, standard rates, $/month			
160 operating hrs/month	$20,250*	*	*Three month minimum rental,
320 operating hrs/month	$30,375*	**	
Unlimited operating hrs/month	$40,500*	**	
Multiple unit discount for XQ2000			
1 Unit, 3 month min.	10.0%	**	Discount from standard rate.
2 Units, 3 month min.	12.5%	**	Discount from standard rate.
3 Units, 3 month min.	15.0%	**	Discount from standard rate.
2500 kVA 480-12.47kV	$4,500	**	
4/0 low voltage conductor	$3.00/ft/month	**	400 amp capacity per run
Configure a unit for arctic	Approx $20,000	**	One time only per unit
Estimated freight northbound/unit	$8,000	**	
Estimate freight southbound/unit	$6,000	**	
Start-up/commissioning tech	$130/hour	**	Plus travel at $90/hour and mileage from Fairbanks.
*Caterpillar (2000). **e-mail from G. Hirschberg (NC Power Systems) to Robert Lorand (SAIC) (11 May 2006).			

Table 30. Costs for renting 2-2 MW diesel generators for 6 months.

Costs for 2 Generators for 6 Months Including O&M	
Item	**Cost**
Fixed Costs	$41,860
Variable - Non-Fuel Costs	$398,260
Variable - Fuel Costs @200 hours of operation @75% load, $3/gallon diesel	$126,000
Total Costs	$566,120

The following items require resolution before this option can be exercised:

- Identify actions required to determine that operation is within regulatory environmental commitments.
- Determine the required diesel fuel storage capacity, and other oil storage requirements such as heat tracing, fire protection measures, oil spillage prevention, etc.
- This option is considered feasible assuming the limited run hours anticipated.

The diesel generator can be connected to the distribution lines in several different ways. Depending on the selected connection method, several hundred thousand dollars could be required above and beyond the rental costs if the installation was connected to the base 12.47 kV pole lines. If connected directly to the CHPP switchgear, the connection cost would be less.

6.2.6 Immediate option 6: shorten ACC downtime for each STG

Information for this option was not available.

6.2.7 Immediate option 7: delay the ACC connection

Information for this option was not available although initial inputs indicated it would be a very costly option.

6.2.8 Immediate option 8: use steam turbines at “5/4” capacity

The original concept of using the steam turbines in its overload, or “5/4” (125 percent capacity mode) is based on the fact that for many steam flow conditions, that STG-3, 4, and 5 are capable of producing power at a level above their rated capacity of 5.0 MW. In fact, with a power factor of 1.0, the STG-3, 4, and 5 can produce 6.25 MW, based on the generator rating of 6.25 MVA. These STGs have historically been operated at 6 MW.

As discussed in Section 1.2, the steam turbines are typically limited by the generator capacity and the power factor at the generator terminals. Since the generator power factor may be required to be 0.80, the 5/4 operation cannot necessarily be counted on. In fact, the 6.25 MVA rating of the generator, and a 0.80 power factor combine to yield an effective capacity of:

$$5.0 \text{ MW } [(6.25 \text{ MVA})(0.80) = 5.0 \text{ MW}].$$

Plant personnel may actually push the generator past the 6.25 MVA rating value, by monitoring select temperatures within the generator. However, no information was available that identifies the MVA value at which the generator can operate continuously without exceeding the critical temperatures.

In view of these factors, counting on any power production above the rated values of 5.0 MW for STG-3, 4, and 5 for an extended period of time does not appear to be prudent.

6.2.9 Immediate option summary

Table 31 lists the options for immediate implementation discussed above. Options 1, 2, and 3 appear to be the most promising.

Option 1 provides an additional 7.5 MVA of capacity (about 7 MW) and possibly up to 10 MVA or more during colder conditions (8.5–10 MW depending on temperature conditions and power factor). In combination with options 2 and 3, this option provides additional reserve margin, a hedge against demand forecast uncertainties. It entails a capital cost of about $1.3 million, if FWA were to purchase it.

Option 2 simply takes advantage of the ability of the transformer to provide greater output during colder conditions, and requires no capital cost outlays. This capability has been used in previous years and GVEA has no objection to using this capability for the future. The increase from 7.5 MVA to 10 MVA will enable the import of about 2 MW of additional power from GVEA if needed.

Option 3 makes use of an existing connection to GVEA that is normally used in emergency situations. The intertie has been used in the past and can provide about 5 MW of additional power from GVEA if needed, and requires no capital cost outlays.

Option 8, operating the STGs above their nominal/nameplate capacity is a feasible option, but operating above the nameplate ratings is possible only under specific operating conditions and may not be available when required.

Options 1, 2, and 3 essentially result in greater purchase of electricity from GVEA, higher electric demand charges, and higher overall utility payments. However they provide a more economical solution than adding temporary generators (Options 4 and 5). Furthermore, Options 1, 2, and 3 do not require substantial capital equipment investment and there are no negative environmental impacts from these options. In contrast the operation of emergency generators will generate air pollutants, even if they are in use for short periods.

Table 31. Options for immediate implementation (winter 2006/2007).

Criteria/Option	1	2	3	4	5	6	7	8
	GVEA Transformer – Used	Increase Intertie Cap (7→10 MVA)	GVEA backdoor Use 5 MW	Prime Power DG Rental	Private Co DG Rental	Shorten ACC Interconnection	Finish ACC Project Do Not Connect	STG at "5/4"
Incr. Power (MW)	7	2	5	4.5	4	2.5 ea	5 ea	(0 to 1.25) ea
Capital Cost	Additional pole line equipment	0	0	\$500K-\$750K+	\$530K+	High	High	0
O&M Cost	Low	Low	Low	High	High	None	None	Low
Operational consideration	None	None	None	Requires operator supervision	Requires operator supervision	None	None	Requires high PF.
Environmental	None	None	None	Increased emission, and fuel transportation/storage	Increased emission, and fuel transportation/storage	None	None	None
Time frame	2-3 months	Immediate	Immediate	1-2 months	1 month	Immediate	Immediate	Immediate
Risk	Low	Low	Low	Low	Low	Low	Low	Moderate
Reliability	High	High	Medium-high	New failure modes	New failure modes	High	High	Medium
Other advantages		No new equipment		Under base control	Under base control			Existing equipment
Other disadvantages	Reduced backup capacity	Does not meet full demand requirement	Does not meet full demand requirement	The 4.5 MW units do not have the necessary auto-switching.	Outside maintenance contracts	Unclear that this solves shortfall, as it is unlikely the schedule can be shortened enough	Delays fulfilling environmental benefit. May complicate warranty issues.	Depends on PF. Decreased equipment life.
Overall feasibility/likelihood of success	Promising	Promising	Promising	Not viable without auto-switching	Viable at moment, but 1st come, 1st serve.	Unlikely	Feasible, but expensive temporary solution.	Unlikely to add any substantial MW, particularly in view of PF.

6.2.10 Definitions of criteria

- *Incr. Power (MW)*. The total incremental power target the immediate option is 10.3 MW (assuming unscheduled outage of one 5 MW turbine, no back door intertie, and no temperature based load increase for the transformer). The planning target assuming use of the back door intertie and temperature based load increase is 2.3–3.8 MW.
- *Capital Cost*. This is the total capital cost of the option. There is not absolute cost limit. However, lower cost options are preferred.
- *Operations and Maintenance (O&M) Cost*. The options with the lowest O&M cost are to be favored.
- *Operational Consideration*. This is to capture operational impacts and/or changes that should be considered in the evaluation.
- *Environmental*. This includes environment limits/concerns or issues that may delay or limit the operation of the subject options.
- *Time Frame*. The time frame to implement the option.
- *Risk*. This generic risk criteria includes technical (feasibility, operational, reliability, etc.), cost, and other financial risk areas.
- *Reliability*. The factor reflects the reliability of the option itself and/or the ability for the entire system to be reliable.
- *Other Advantages*. Other areas as documented.
- *Other Disadvantages*. Other areas as documented.

6.3 Short-term capacity shortage options

Table 32 lists short-term capacity alternatives developed as possible solutions to the “short-term” capacity shortage problem. These alternatives are discussed further in the following subsections. The options fall largely into three broad categories: (1) upgrading transformer/substation capacity to enable increased power purchases from GVEA or other sources; (2) upgrading/modifying the STGs to increase capacity; and (3) providing power from diesel generators.

Table 32. Short-term capacity shortage options—feasible.

No.	Description
1	New diesel generator set
2	New permanent 10 MVA transformer
3	New mobile 2 x 10 MVA substation

No.	Description
4	New substation to meet year 2020 demand: 2 x 20 MVA
5	Install volt-ampere-reactive (VAR)* compensation to increase MW generation capability
6	Separate power line from clear AFS
7	Wheel power from Eielson AFB
8	Use Elmendorf AFB STG—replace 1 or 2 existing STG
9	Use Elmendorf AFB STG—add 1 or 2 existing STG
10	Replace STG-1 and/or STG-2 with new STG
11	Repair/modify STG-1 and/or STG-2

6.3.1 Short-term option 1: purchase diesel generator set

The option of purchasing diesel generators for base load power generation is similar to renting diesel generators (see Section 6.2.5). The main differences with purchasing the equipment are the lead time for purchasing the generators, the additional infrastructure required, and the costs. If diesel generators were purchased for use as permanent plant equipment, they would require permanent structures and installation of supplementary systems. The fuel storage and handling facilities would be more critical. In addition, it is likely to be very difficult to permit this installation, or that such a permit might have a limitation on the operating hours that could prove too restrictive in future years. The capacity of the two diesel generators considered are 3.0 MVA each.† Figure 26 shows a possible configuration for the diesel generators. Table 33 lists the estimated capital costs for this option.

The consensus during the 30 May 2006 Project telephone conference was that purchasing diesel generators for base load operation is not a feasible solution based on environmental and operating and maintenance cost considerations.

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* The term VAR stands for volt-amperes-reactive, which is the power that is stored in inductive loads such as motors or transformers, and is not available to do useful work.

† This 6 MVA option would not meet the long term growth by itself, but could be part of a multi-pronged solution. The 3 MVA diesel generator capacity is based on the assumed size of the largest motor, and not a result of a detailed sizing calculation. Should this option proceed to the procurement phase, a detailed sizing calculation based on mechanical equipment and client requirements would typically be performed. Budgetary quotes such as this, are typically based on preliminary yet conservative size estimates.

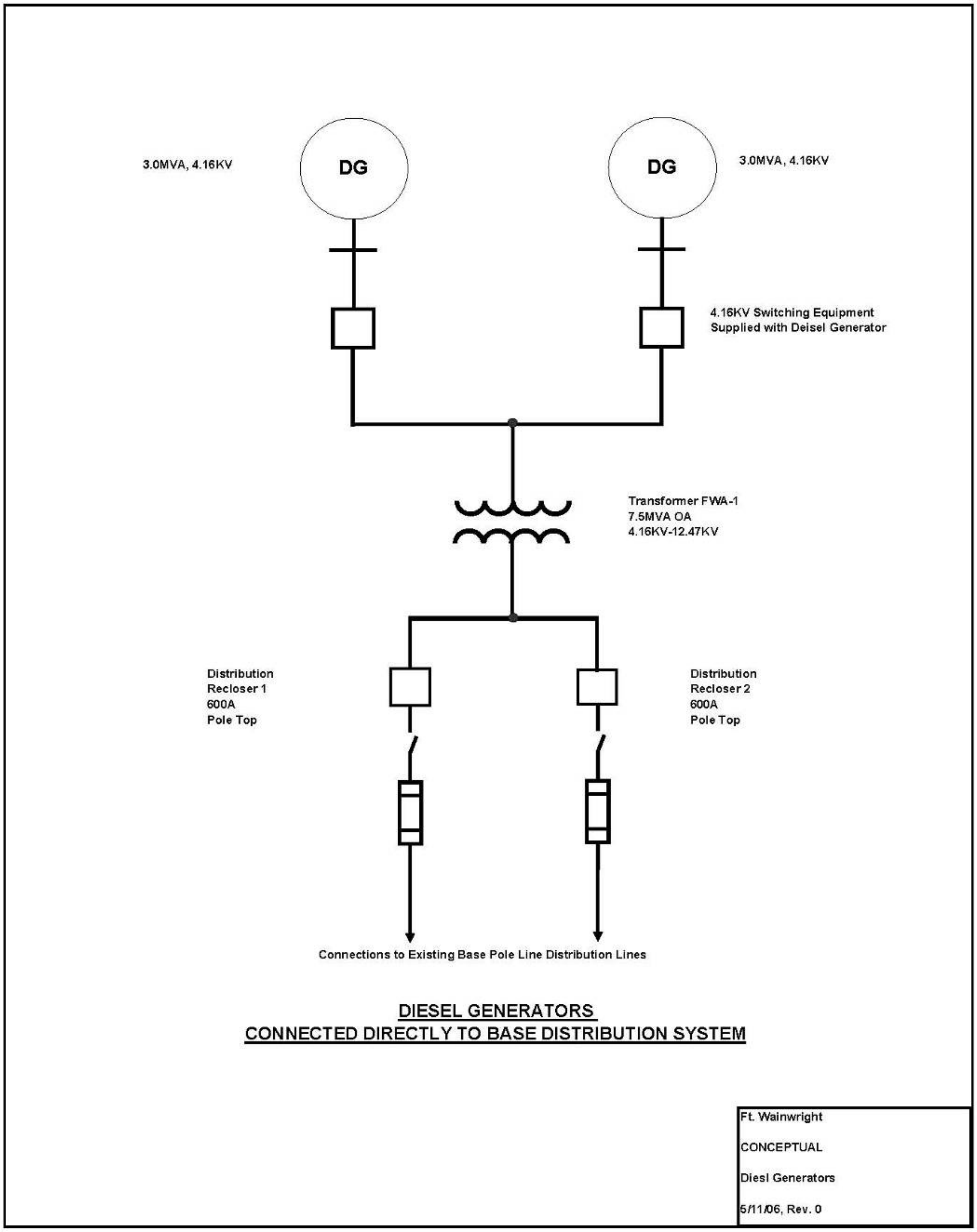


Figure 26. Short term option 1 (purchase of commercial diesel generator) 1-line diagram.

Table 33. Short term option 1—diesel generator estimated capital costs.

Item No	Specification	Rating	Volts	Qty (ea)	Unit Cost	Lead Time (Weeks)	Total Cost	Comments
Transformers								
1	7.5 MVA oil filled transformer	7.5MVA OA	4.16KV-12.47KV	1	$251,200	50	$251,200	
1a	Transformer foundation			1	$38,080		$38,080	
1b	Transformer grounding			1	$4,168		$4,168	
15KV Substation								
2	Fused disconnect switch	200A	15KV	2	$18,660	25	$37,320	Distribution Type, Pole mounted, Gang Operated
3	Distribution recloser	600-800A	15KV	2	$4,942	25	$9,884	Similar to ABB Type ESV
4	Lightning arrestor		15KV	6	$1,496	25	$8,976	Distribution Type, Pole mounted
4a	Substation grounding			1	$7,780		$7,780	
4b	Substation control wiring			1	$36,680		$36,680	
5	Diesel generator	3.0MVA	4.16KV	2	$1,632,000	50	$3,264,000	Provided with Fuel tank and switching equipment
Overhead Lines								
6	12.47KV distribution pole line	1/0	12.47KV	1 mile	$106,000		$106,000	Single 3 ph ckt, wood construction
Cable, Insulated								
7	Medium-voltage cable	500MCM	5KV, Shielded	1000	$23		$23,324	
	Subtotal						*$3,787,412*	
	Allowance for engineering and CM (~10%)						$379,000	
	Contingency (~10%)						$417,000	
	Total						***$4,583,412***	

Notes/Basis:

1. The estimate shows the major equipment costs for an installation similar to that shown in Figure 26, which includes distribution equipment that is not required for all configurations of the diesel generators.
2. The costs are an estimate and not based on quotes or detailed Scopes and are ±30 percent.

6.3.2 Short-term option 2: new permanent 10 MVA transformer

The option of purchasing a new 10 MVA transformer to provide the short-term load increase was investigated and is a technically feasible solution. The transformer could be procured and installed within the short term time frame. The transformer could be connected to Fort Wainwright in a manner similar to the new, temporary, 7.5 MVA transformer, however this is not recommended due to the age of the existing switchgear.

The transformer size (10 MVA–about 8.5 MW–9 MW) should be compared against future load requirements. A larger (e.g., 20 MVA–about 17 MW–18 MW) transformer seems indicated for meeting the incremental power requirements in the year 2020.

The choice as to purchasing a transformer or having GVEA provide the transformer would be made based on cost details of the power agreement between Fort Wainwright and GVEA. Additionally, the substation equipment (e.g., switching and control equipment and bus) could be owned by GVEA or by Fort Wainwright with the decision based on economic factors.

As with the temporary 7.5 MVA transformer (Section 6.2.1) the new 10 MVA or 20 MVA transformer could be configured in several ways. The configuration depends on trade offs between reliability, redundancy, and costs. Several configurations are discussed below.

Make connections using new switching equipment near the new transformer to the areas at Fort Wainwright that require the power. This would result in a portion of the Fort Wainwright not connected to the CHPP and without back up. This configuration would be the same as described under bullet 1 in Section 6.2.1.

Add and modify the switching arrangement of the over head lines near the CHPP to connect to the 12.47 kV “Feeders.” The new transformer could be connected to the existing overhead pole line feeders by installing a new outdoor substation near the CHPP.

Place the new transformer in parallel with the existing transformer and modify the existing 12.47 kV switchgear. This option may be a cost effective Short Term solution, but would decrease overall reliability and redundancy and does not support Long Term objectives. Also, this option is **not recommended** due to the status of the existing switchgear.

Table 34 lists the major equipment costs for a 10 MVA substation. This cost estimate is essentially identical to the 7.5 MVA option except that the 10 MVA transformer is marginally more expensive. For reference, the cost estimate is representative of the first connection option presented above. The items presented in the cost estimate are consistent with Figure 24, and considers all items in Fort Wainwright's Scope, with typical costs that are approximately ±30 percent.

6.3.3 Short-term option 3: new mobile 2 x 10 MVA substation

A mobile substation could be obtained from GVEA (or others). However, a mobile substation available from GVEA would not be available exclusively for Fort Wainwright, and could be withdrawn on relatively short notice. After consideration and discussion, the team determined that this option was not worth pursuing due to cost and reliability factors.

6.3.4 Short-term option 4: new substation to meet year 2020 demand

The purpose of this section is to consider the factors involved in installing a new substation in the short term that meets the load forecast for 2020. That section also describes a possible electrical system configuration which would also apply to a 20 MVA transformer. Cost information for major capital equipment is provided at the end of this section based on one possible system configuration (Table 35). This configuration assumes 2 x 20 MVA transformers, a capacity sufficient to meet the full requirements of FWA in the event the CHPP was unavailable. The estimated cost is approximately $9.3 million, including $4.0 million for black start diesel generators ($5.3 million without the generators). Note that the CEHNC estimate for a new substation using 2 x 15 MVA transformers is about $7.8 million (see Appendix C).

Table 34. Short term option 2—new 10 MVA transformer, estimated capital cost.

Item No	Description	Rating	Volts	Qty (ea)	Unit Cost	Lead Time (Weeks)	Total Cost	Comments
Transformers								
1	10 MVA oil filled transformer	10MVA, OA, 65C	69KV-12.47KV	1	$346,200	50	$346,200	
1a	Transformer foundation			1	$38,080		$38,080	
1b	Transformer grounding			1	$4,168		$4,168	
15KV Substation								
2	Fused disconnect switch (cut out)	600-800 A	15KV	1	$20,360	25	$20,360	Distribution Type, Pole mounted
3	Fused disconnect switch (cut out)	200A	15KV	2	$18,660	25	$37,320	Distribution Type, Pole mounted
4	Distribution recloser	600-800A	15KV	2	$4,942	25	$9,884	Similar to ABB Type ESV
5	Lightning arrestor	15KV Class	15KV	6	$1,496	25	$8,976	Distribution Type, Pole mounted
5a	Substation grounding			1	$7,780		$7,780	
5b	Substation control wiring			1	$36,680		$36,680	
Overhead Lines								
6	69KV transmission line	336 AL	69KV	1 mile	$398,000		$398,000	
7	12.47KV distribution pole line	1/0	12.47KV	1 mile	$106,000		$106,000	single 3ph ckt, wood construction

Item No	Description	Rating	Volts	Qty (ea)	Unit Cost	Lead Time (Weeks)	Total Cost	Comments
	High voltage sub-station equipment 69KV							
8	High voltage dis-connect switches	600-800A	69KV	1	$31,200	40	$31,200	
9	Utility metering			1	$50,560	25	$50,560	
	Subtotal						*$1,095,208*	
	Allowance for engi-neering and CM (~10%)						$110,000	
	Contingency (~10%)						$120,000	
	Total costs						$1,325,208	*See Notes*

Notes/Basis:

1. The estimate shows the major equipment costs. It does not include costs that may be associated with environmental considerations for disposal or control of the items removed. The ACC switchgear sections are not included.
2. The estimate is based on typical cable lengths and sizes, and, does not include control or instrumentation cable.
3. The costs are an estimate and not based on quotes or detailed Scopes and are ±30%.

New switching equipment is required to connect a new transformer to the CHPP facility. The high voltage switching equipment, conductors and the transformers used to convert the electrical energy to lower voltages is frequently called a substation. It is common for the substation to be provided by the utility. For bulk energy consumers such as Fort Wainwright, it is also possible for the consumers to provide the substation in return for a lower cost of energy.

A new substation that includes a new transformer, new switching equipment, and distribution equipment could be installed to meet the load requirements. The substation and transformer could be purchased and installed by Fort Wainwright or by GVEA, depending on cost and the power agreement.

A new substation connected at 69 kV in place of the existing substation would offer a slight increase in reliability since new equipment would be installed. A new substation at 138kV would offer somewhat more reliability over the existing connection because the equipment would be new, and because, statistically, the 138kV system is more reliable than the 69kV system.

A new substation tied to the GVEA 138 kV system used in addition to the tie point at 69kV could provide additional reliability and provide some redundancy (Figure 28). A new tie to the 138kV system would allow for continued operation at Fort Wainwright with if the CHPP's generation were to go out of commission, or were the 69kV system to fail. The additional flexibility would enable the CHPP to schedule generation outages and arrange for repair of damaged equipment without a major impact to Fort Wainwright's electrical distribution.

The new equipment could be configured in different ways. Figure 27 shows a configuration that uses indoor switchgear for the switching and control of the individual Base distribution pole line feeders. The switching operations could also be accomplished using a new outdoor substation. The configuration would be similar to a conventional utility substation. Black Start Diesel Generators are also shown. The option of including Black Start Diesel Generators would enable the CHPP to restore electrical power if the GVEA system were lost and the CHPP generators were off line.

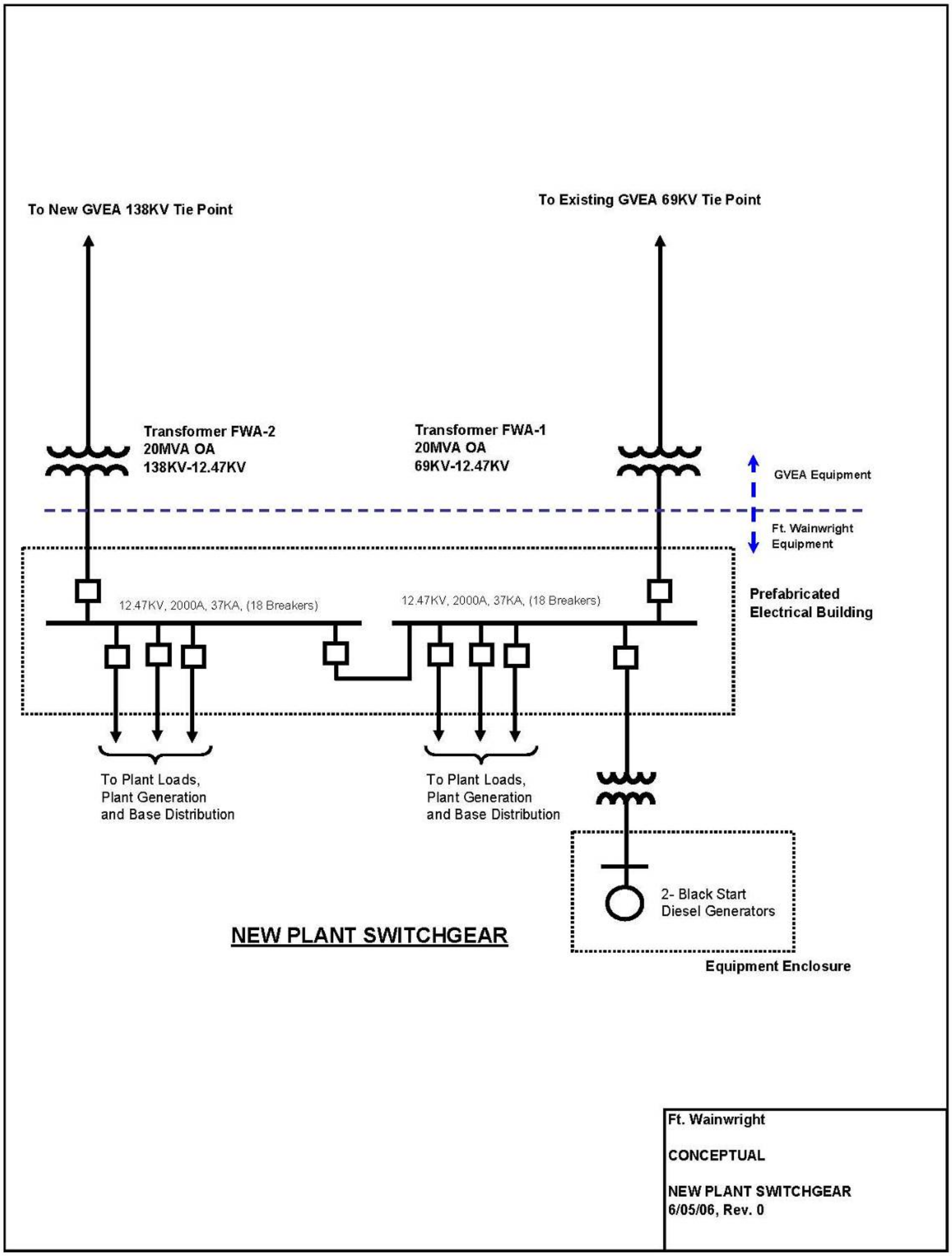


Figure 27. Short-term option 4—new plant switchgear/substation for year 2020 demand.

Table 35. Short-term option 4—new switchgear estimated capital costs—installed.

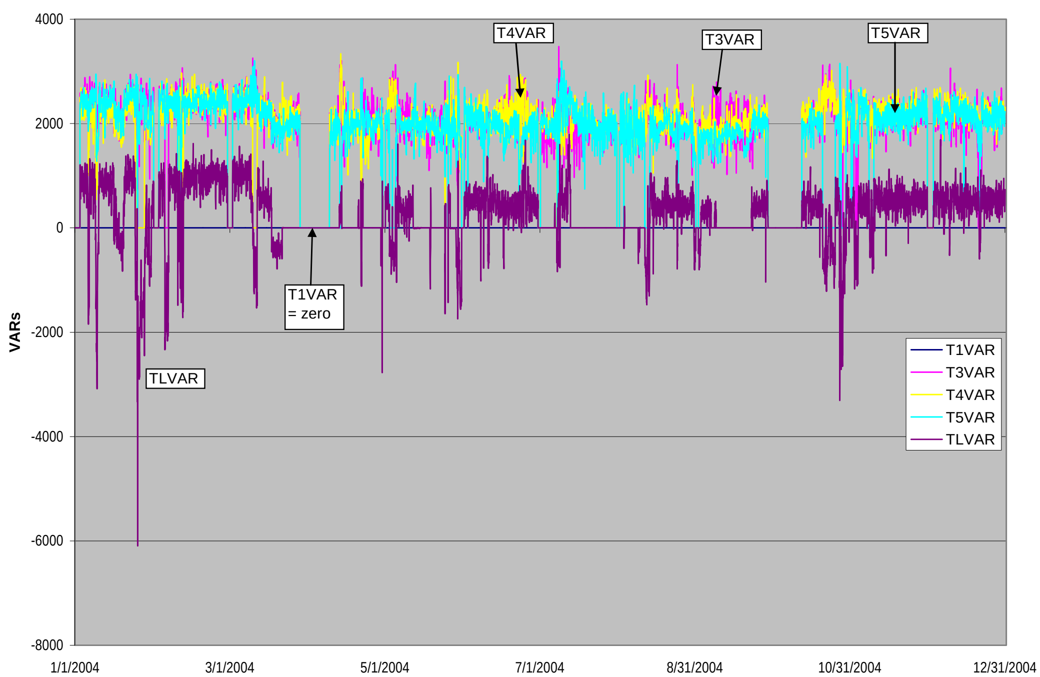
Item No	Specification	Rating	Volts	Qty (ea)	Unit Cost	Lead Time (Weeks)	Total Cost	Comments
				Transformers				
1	20MVA oil filled transformer, with ±10% load tap changer	20MVA OA	138KV-12.47KV	1	$550,000	50	$550,000	
1a	Transformer foundation			1	$12,800		$12,800	
1b	Transformer grounding			1	$2,000		$2,000	
2	20MVA oil filled transformer, with ±10% load tap changer	20MVA OA	69KV-12.47KV	1	$460,000	50	$460,000	
2a	Transformer foundation			1	$12,800		$12,800	
2b	Transformer grounding			1	$2,000		$2,000	
3	Prefabricated electrical building	20FT x 70FT	N/A	1	$294,000	30	$294,000	
4	15KV Metal clad switchgear, 36 vertical	2000A, 37KA	12.47KV	1	$1,512,000	30	$1,512,000	Designed for artic conditions
6	Protective relay panel	36 x 36 x90 in.	N/A	1	$75,000	25	$75,000	
7	Uninterruptible power supply	50KVA	120VAC	1	$45,000	40	$45,000	
8	Substation battery and charger	500AHr	125VDC	1	$200,000	40	$200,000	
8a	Grounding			1	$3,000		$3,000	
9A	Diesel generator	3.0MVA	4.16KV	2	$1,500,000	50	$3,000,000	
9B	Diesel generator enclosure			2	incl above		incl above	
9C	Diesel generator day tank			2	incl above		incl above	
				Cable, Insulated				
10	High-voltage cable	500MCM	15KV, Shielded	3,000	$6		$18,900	
11	High-voltage cable	1/0AWG	15KV, Shielded	10,000	$3		$30,000	

Item No	Specification	Rating	Volts	Qty (ea)	Unit Cost	Lead Time (Weeks)	Total Cost	Comments
11a	Control wiring			1	$7,500		$7,500	
12	Concrete duct bank	20-4-in. Con-duits	MV	100	97		$9,700	
				Construction costs				
13	Install new prefab elec bldg (item 3)			1	$35,000		$35,000	
14	Install transformers (Items 1 and 2)			2	$99,000		$198,000	
14a	Transformer foundation (1a,2a)			2	$63,360		$126,720	
14b	Transformer grounding (1b, 2b)			2	6,336		$12,672	
	Install 15kV switchgear (item 4 and 5)			1	$190,080		$190,080	
	Install protective relay panel (item 6)			1	$5,280		$5,280	
	Install UPS (item 7)			1	$5,280		$5,280	
	Install battery and charger (item 8)			1	$26,400		$26,400	
	Install grounding (item 8a)			1	$6,336		$6,336	
	Install diesel gen (item 9)			2	$132,000		$264,000	
15	Demo existing 12.47KV switchgear, assume 26 vertical sections			1	$68,640		$68,640	
16	Remove existing 15KV cable			10,000	$9		$92,400	
17	Install new MV cable (items 10,11)			13,000	$15		$197,340	
17a	Install control wiring (item 11a)			1	$39,600		$39,600	
18	Install new duct banks (item 12)			100	1487.64		$148,764	
	Other items (not included)							
	High voltage substation 138KV			N/A			N/A	Not included
	High voltage substation equip 69KV			N/A			N/A	Not included

Item No	Specification	Rating	Volts	Qty (ea)	Unit Cost	Lead Time (Weeks)	Total Cost	Comments
	138KV transmission line			N/A			N/A	Not included
	69KV transmission line			N/A			N/A	Not included
	12.47KV distribution line			N/A			N/A	Not included
	Plant DCS system			N/A			N/A	Not included
	120VAC power panels							Include in build-ing
	125VDC power panels							Include in build-ing
	LV Cable and conduit							Include in build-ing
	Subtotal						*$7,651,212*	
	Allowance for Engin. and CM (~10%)						$765,000	
	Contingency (~10%)						$842,000	
	Total						***$9,258,212***	
Notes/Basis: The estimate shows the major capital equipment costs, ±30%.								

6.3.5 Short-term option 5: install VAR compensation to increase MW generation capability

The CHPP generators supply real power (Watts) and reactive power (VARs, or Volt-Amperes Reactive) to meet Fort Wainwright's electrical energy requirements. The CHPP generators do not have automatic VAR compensation installed. This means that the operators have to check and manually adjust the generator controls to change the generated VARs to meet the electrical demand and keep the power factor within acceptable limits. Figure 28 illustrates the wide variation of the generators VARs with time. When the generator is operating at its thermal capacity, generating more VARs than required has the effect of limiting the generators' maximum real power generation (refer to discussion in Section 2.2.). CHPP personnel have noted that, if automatic VAR compensation were installed, the power available from the generators would be increased. The power increase from using automatic VAR compensation would not require any mechanical changes to the steam turbine generators and would provide greater generator control.



Source: e-mail from G. Hirschberg (NC Power Systems) to Robert Lorand (SAIC). (11 May 2006).

Figure 28. Tieline and STG VAR change over time (1 year).

6.3.6 Short-term option 6: separate power line from clear AFS

This option involves installation of a dedicated transmission line from Clear AFS to FWA. Building the line would be necessary since Clear AFS is not connected to the grid. The estimated cost for the line is $32 million based on an 80-mile line at a unit cost of $400,000/mile.* Transformers would also need to be added at FWA to make use of this power. Based on the cost of the option and the procedural hurdles to obtain right-of-ways for the line, this option was not considered to be practical.

6.3.7 Short-term option 7: wheel power from Eielson AFB

About 3 MW of power could be provided by Eielson AFB to FWA based on the projected needs of Eielson and their CHPP's generating capacity. The terms of the power purchase would need to be arranged with both Eielson and GVEA, since the power would be "wheeled" across GVEA's system. GVEA would impose wheeling charges and FWA would need to make payments to cover the marginal costs of operating the Eielson CHPP for supplying power to FWA. This option will not require a capital investment by the Fort, other than potentially a new intertie transformer. Sufficient intertie capacity (e.g., transformer capacity) must be available if this is to be used to meet peak power requirements. The wheeling, in and of itself, does not address the capacity shortfall, but only where the electric energy supplied from the intertie is purchased. If the level of excess generation at Eielson increases in the future, this option may require further investigation. It may be possible to use the Eielson generation as "Stand By" or "Reserve" capacity but further study would be required to determine if it would be an economically viable alternative.

6.3.8 Short-term option 8: use Elmendorf AFB STG—replace 1 or 2 existing STG

The Elmendorf AFB steam turbine generator option involves installing one or two of the nominal 9.3 MW, 400 psig, 700-725 °F Elmendorf STGs (Fort Wainwright 8–12 May 2006) in place of existing STGs at FWA to provide additional generating capacity. Each Elmendorf units has been estimated to require a 30 x 30-ft footprint which is not available at the FWA CHPP (FWA STG 1 requires 12 x 26 ft and STG 2 requires 26 x 9.25-ft floor

*Unit cost estimate from Mike Wright of GVEA.

area). As such, this option would seem to require a new separate turbine building and new steam and cooling interconnections (e-mail from John Vavrin to Kenneth Hudson WorleyParsons 24 May 2006). Also, since the units are condensing units, they would also need a new ACC. It is noted that the ACC project for the 3 x 5 MW STG cost $30 million. Finally, since a decision to take the units needed to be made in the June timeframe, it was decided to eliminate this option from further consideration.

6.3.9 Short-term option 9: use Elmendorf AFB STG—add 1 or 2 existing STG

The Elmendorf AFB steam turbine generator options were ultimately removed from the options list following the 1 June 2006 teleconference. The rationale for removing this option is consistent with the rationale presented above.

6.3.10 Short-term option 10: replace STG-1 and/or STG-2 with new STG

This option considers the replacement of STG-1 and STG-2 with new similarly sized and larger STG(s). The feasibility/economics of replacing existing turbines is related to many factors. The primary factors are:

- availability of space
- adequacy of existing cooling (e.g., cooling pond, ACC)
- adequacy of existing steam supply
- adequacy of existing steam piping
- adequacy of steam demand
- extent of required pedestal modifications
- adequacy of existing transformer/electrical system.

These factors have been considered in the evaluation the several different steam turbine generator replacement options.

The CHPP steam turbines and control room are located in the turbine hall on the eastern side of the plant building (See Figure 29). The turbine hall occupies the area between column lines B and P (~235 ft north to south), and column lines 14 and 17 (~ 60 ft east to west) at the plant elevation of 115 ft (e-mail from Allan Lucht to Donald LaRocque 1 June 2006). With the exception of STG-2, all turbines are arranged parallel to the north-south axis. The STG-2 is arranged transversely to the north-south axis.

Figure 29 shows the turbine floor for STG-1 and STG-2. From this floor plan, the turbine pedestals have been scaled as 10.5 ft x 28 ft and 8.7 ft x 26 ft for STG-1 and STG-2 respectively. Plant measurement report the turbine 1 foundation as 12 ft x 26 ft and turbine 2 foundation as 26 ft x 9.25 ft (ZBA, Inc. Engineers/Consultants Undated). A major observation from these measurements is that the 5 MW unit is only slightly larger than the 2 MW unit, and that additional free space is available for slightly larger machines. It is also noted that the mechanical exciters occupy approximately 8 or 9 ft of that length. Modern electronic based exciters take significantly less room, thus freeing up space for a larger machine.

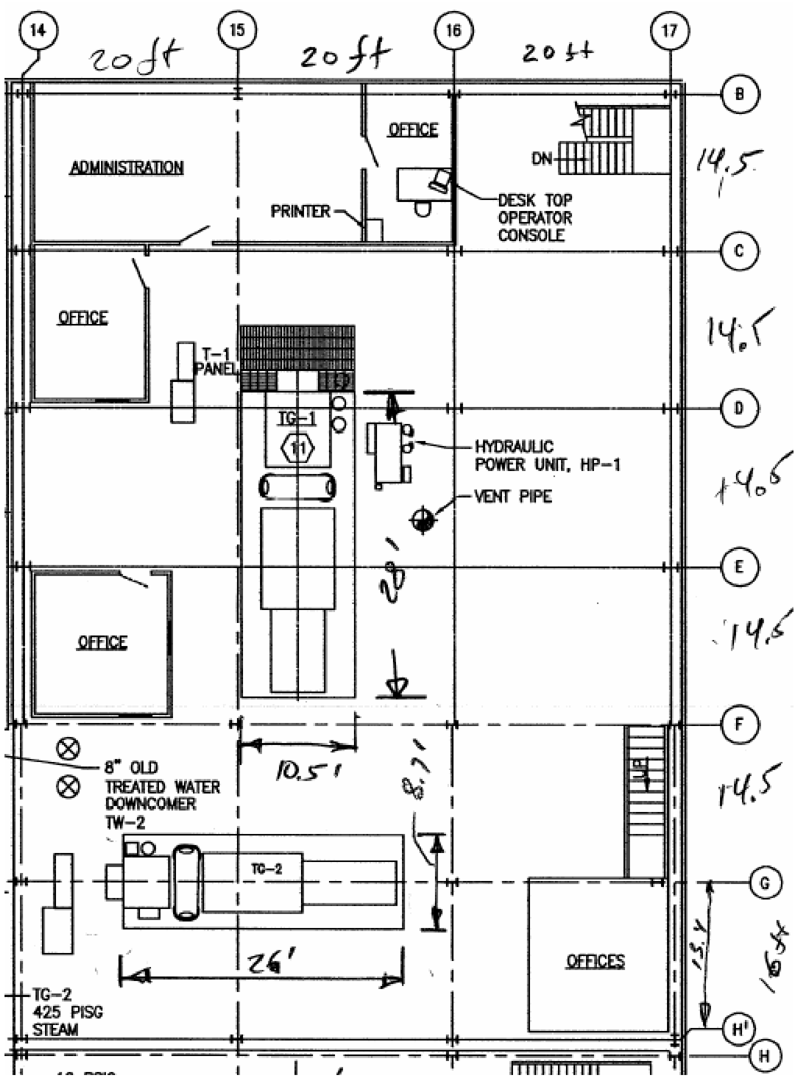


Figure 29. Fort Wainwright turbine hall floor plan for STG-1 and STG-2.

The condensing turbines STG –2, –3, –4, and –5 are designed with bottom steam exhaust. Their respective condensers were originally located immediately under the turbines between the elevations of 115 ft and 100 ft. As a part of ACC project STG-3, STG-4, and STG-5 condensers are being replaced with the steam exhaust ducts. The condenser of non-operational STG-2 is assumed to be abandoned in place.

STG-1 is a 5 MW back-pressure machine, supplying 10 psig exhaust steam for plant needs. It is also equipped with the controlled extraction at 100 psig. The 100 psig steam extracted from STG-1 is sent to the Fort Wainwright heating system. Due to the reduced plant demand for 10 psig steam, the STG-1 output is currently limited to 3 MWe (4 MWe depending on operating conditions).

Numerous options were considered for replacing STG-1 and STG-2 with new steam turbines. Tables 36 and 37 lists several of the more obvious options. Options that are less desirable are shaded grey, while the option selected for the development of a preliminary cost estimate is shown with a white background.

Table 36. STG-1 replacement options.

Option	Advantage	Disadvantage	Comments
Replace “in kind” (i.e., 5 MW back pressure unit) modified to exhaust at 100 psig steam in view of a diminished 10 psig steam demand.	With redesigned steam conditions, can achieve 5MW.	This could be accomplished much more cheaply by retrofitting the existing STG. Will require pedestal modifications as new turbines will attach differently. Will require more throttle steam than the original design.	If this configuration is logical, than it should be instituted via a repair/modification, and not as a new machine. The repair/modification would achieve the same result much more cheaply. **This option is not recommended.**
Replace with larger back pressure unit	Would generate additional MWs.	The increased 100 psig steam exhaust flow rate required to generate more than 5 MW is likely to significantly impact the operational flexibility of the other turbines and may cause the ACC capacity of the condensing STGs to be inadequate.	It is unlikely that an increased capacity BP turbine will prove feasible in light of the demand for 100 psig steam, CHPP operational flexibility, and its potential impact on the newly installed ACC. **Not recommended.**

Option	Advantage	Disadvantage	Comments
Replace STG-1 with a condensing unit (of similar size, ~5 MW)	Increased operational flexibility over a backpressure unit	Requires an expensive ACC May not have sufficient room underneath the STG to connect to the ACC.	The option below provides more capacity, and benefits from only having to install 1 new STG instead of 2. The following unit was selected over this option.
Replace STG-1 and STG-2 with a single larger condensing machine (~10 MW)	Compared to the existing 3-4 MW STG-1, this adds ~6-7 MW. Requires similar modifications (new steam lines, new ACC, pedestal mods, I&C modes, etc.) to above option, while adding more capacity, thus being more cost effective.	Being larger than the other STGs, losing this single machine may create capacity problems depending on other conditions and scenarios. It may be more cost effective to repair/modify the existing STG-1 and STG-2	This option adds the most capacity, and would benefit from the economy of scale. **This option was selected for developing a preliminary cost estimate.**

Table 37. STG-2 replacement options.

Option	Advantage	Disadvantage	Comments
Replace in kind (2 MW condensing unit)	Similar sized unit	200 psig extraction steam is no longer used. Requires ACC or cooperation with existing ACC, which would reduce operational flexibility. Only provides additional 2 MW. Would require a pedestal mod, even with the original 2 MW capacity, since new machines have different footprint/attachment points than the 1950s STG.	This option only provides 2 MW. A larger condensing unit would have a much better economy of scale. Additionally, it is likely that refurbishing the existing 2 MW unit would also be more cost effective. **This option is not recommended.**
Replace with larger Condensing unit (roughly 5 MW)	Adds 3MW more than 2 MW unit. Likely that there is sufficient room, as the 5 MW unit is not much larger than the 2 MW unit.	Likely that pedestal condenser opening is too small. Would require significant enlargement. Would require an expensive ACC. Requires pedestal modifications.	It is likely to be less cost effective than the following option that replaces both steam turbines 1 and 2. **The following option is preferred over this option.**
Replace STG-1 and STG-2 with a larger machine (~10 MW)	See STG-1 Table	See STG-1 Table	Of the replacement options, this option adds the most capacity, and would benefit the most from an economy of scale. **This replacement option was selected for developing a preliminary cost estimate.**

Per the considerations listed above in Table 36 and Table 37, the new replacement steam turbine option selected for the development of a preliminary cost estimate is the replacement of STG-1 and STG-2 with a single new condensing steam turbine generator with an extraction at 100 psig. This new machine will not exhaust nor have an extraction at either 10 or 200 psig respectively. A review of the original heat balance and many other factors has revealed that an estimated maximum size of this unit would be approximately 10 MW. This assumes maintaining the original CHPP design criteria of being able to run all steam turbine generators with one boiler out of service. In addition, going above 10 MW increases the generation capacity that would be lost when the unit is unavailable. Thus 10 MW was selected as a reasonable capacity basis for STG replacement.

This replacement option is based on demolishing STG-1 and STG-2 and replacing them with a new 10 MW 400psig/650 °F steam condensing turbine generator with a 100 psig controlled extraction; adding a new dedicated ACC; modifying the pedestal for attachment and the increased exhaust flow; connecting new larger steam lines, and implementing other required modifications. This option has been estimated to cost approximately $45 million, and includes professional services, freight, and a 20 percent contingency.

Considering that this option replaces STG-1, which is currently rated at 3 to 4 MW depending on the ambient condition, this option only adds 6 to 7 MW of capacity, at a cost of approximately $7000/kW. The existing steam turbines can be repaired or modified to add new capacity much more economically (in terms of cost per kW). The following section discusses these repair/modify options.

6.3.11 Short-term option 11: repair/modify STG-1 and/or STG-2

With STG-1 being derated due to a lack of 10 psig steam demand and STG-2 being abandoned in place, a logical potential option is the repair/modification of these steam turbines. There are several reasons to consider this repair option as listed below (e-mail from Pat Driscoll to John Vavrin 26 May 2006):

- Vintage 1950 GE machines are reliable workhorse machines.
- These machines are direct drive machines and will not have an efficiency loss associated with a gear box typical of new machines.

- The machines were designed to be completely repairable
- The casings of these industrial class machines almost never fail. Casing failure would be the main reason for replacing these machines.

The repair of the existing machines will cost substantially less than adding new units (i.e., lower equipment costs, no modifications required for the pedestal, and no or few modifications required for the electrical system, control systems, steam lines, interconnections, etc.).

The repairs/modifications could result in a potential capacity increase of about 4 MW from the two units (i.e., about 2 MW from each unit). The following subsection presents the repair/modification considerations for both STG-1 and STG-2.

6.3.11. STG-1 repair/modification considerations

A possible repair/modification option for the STG-1 is to exhaust steam to 100 psig instead of the 10 psig steam. This could be accommodated by eliminating the LP section (i.e., the section after the 100 psig extraction point) and uprating the HP section of the unit to increase its flow passing capability as much as possible to possibly the full 6250 kW (with a PF of 1.0). Typically this would require drilling new penetrations through the casing and adding extra 100 psig extraction piping to remove the additional steam from the steam turbine. This type of conversion is performed on a regular basis. Depending on the specifics of the flange and piping, the addition of new penetrations and steam lines may or may not be required (see Figure 30). The future evaluation of this option should also include consideration of possible impacts to operations because for this non-condensing STG to develop power, all exhaust steam (approximately 180 kpph at 5 MW) must go to the 100 psig header.

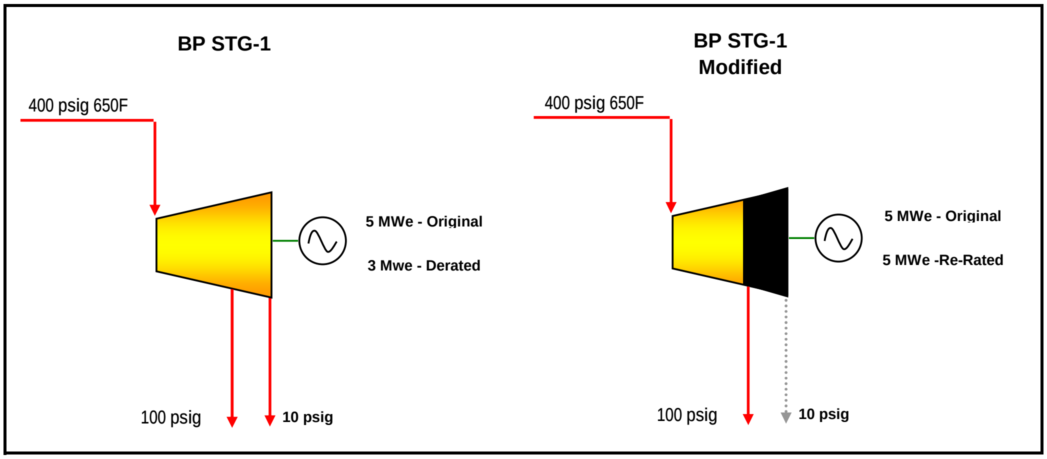


Figure 30. Short-term option 12—potential STG-1 steam path modification.

To further evaluate this option, WorleyParsons contacted TurboCare Inc., who reviewed the following information:

- unit performance curves and extraction map
- generator rating
- unit cross section.*

Based on this information, TurboCare performed a preliminary evaluation of the uprate-ability and convert-ability of STG-1 to run as a straight non-condensing unit by eliminating the LP section and passing enough flow from 400 psig to 100 psig to max the generator out at 6,250 kW. Table 38 lists the current and uprated characteristics of STG-1, based an assessment by TurboCare, Inc. (e-mail from Kevin Lord (TurboCare Inc) to Martin McDonough, CC: Vlad Vaysman/Dave Stauffer (WorleyParsons) 13 June 2006).

* The mechanical outline 513E906 was provided by personnel from Fort Wainwright for the evaluation of STG-1. The outline did not clearly indicate that it was for STG-1, but indicated that the turbine has the GE serial number of 104771. This evaluation presumes STG-1 and GE SN 104771 are one and the same.

Table 38. STG-1 current vs. potential up-rated characteristics.

Parameter	Current TG-1	Uprated TG-1	Notes
Inlet pressure, psig:	400	400	
Inlet temperature, °F	650	650	
Inlet flow, pph	168,000 [iii]	180,000[i] 221,000 [ii]	i. Estimated for 5000 kW ii. Estimated for 6250 kW, at PF 1.0 iii 5000 to 6250 kW, depending on 100 psig extraction and PF.
Extraction pressure, psig	100	100	Exhaust pressure for uprated TG-1
Extraction temperature, °F	~460	~424	Exhaust temp. for uprated TG-1. 460 °F per: H.W. Beecher Architects. (Rev. 1, 22 July 1952).
Max extraction (100 psig) flow rate, pph	125,000	221,000	
Max LP section flow, pph	~128,000	LP Section Eliminated	
LP exhaust pressure, psig	10	LP Section Eliminated	
Max gen capability, kW, at 1.0 PF	6250	6250	Currently limited to 3 to 4 MW depending on ambient.
Max original efficiency, %	67.5 [i]	75 ii	i. Calculated from performance map ii. Estimated potential redesign efficiency
Source: e-mail from Kevin Lord (TurboCare Inc) to Vlad Vaysman/Dave Stauffer (WorleyParsons), 21 June 2006.			

Although the original max efficiency is approximately 67.5 percent, as determined from the performance map, there is a potential that with the latest technology high efficiency steam path components and a re-optimization of the steam path, that the overall efficiency would be approximately 75 percent. The above power and flow estimates are based on this 75 percent efficient steam path. The new exhaust temperature at full flow is estimated to be approximately 424 °F, which is consistent with the heating steam requirements of approximately 400 °F.

To determine the adequacy of the existing steam piping and flanges, the steam passing capacity of the inlet and extraction nozzles/piping was also evaluated. This evaluation is based on the sizing information listed in Table 39. Table 40 lists the corresponding flow passing capability.

Table 39. Flange/pipe sizing data for flow passing evaluation.

Flange/Pipe	Size/Class	Reference	Notes
Inlet flange	10-in./400#	*	Assumed diameter 10.0 in. for calculations
Extraction flange (new exhaust flange)	18-in./400#	**	Assumed diameter 16.9 in. for calculations. Pressure class of 400# assumed.
Extraction piping	16-in.	**	A note on the mechanical outline states that the flange is 18 in. but that piping only needs to be 16 in. The OEM used standard extraction module flange sizes. Thus OEM used a larger size flange and a reducer would allow for a smaller/cheaper line size.

* H.W. Beecher Architects. rev. 1, 22 July 1952.
**General Electric (GE). Undated.

Table 40. STG-1 preliminary flow passing capability review.

Flange/Pipe	Steam condition	Velocity Limit	Flow Capacity	Notes
Inlet flange	400psig /650F	225 ft /sec	293,000 pph	Flange, TTV and inlet piping assumed as 10 in.
Extraction flange (new exhaust flange)	100psig /424F	250 ft /sec	317,000 pph	Assumed diameter 16.9 in. for calculations. No penetrations are required.
Extraction piping	100psig /424F	250 ft /sec	250,000 pph	Piping OD of 16 in. and ID of 15 in. is assumed.

Source: e-mail from Kevin Lord (TurboCare Inc) to Vlad Vaysman/Dave Stauffer (WorleyParsons) 21 June 2006.

Since the flow passing ability of all the relevant piping, valves, and flanges are above the required steam flow of 221,000 pph (to achieve 6250 kVA), no new piping or additional flange area (i.e., penetrations) is required. Thus, the STG-1 machine is an excellent candidate for an up-rate and conversion. The over sizing of the inlet and extraction flanges/piping from the OEM provide ample up-rate capacity. In appears feasible and cost effective to increase the flow in the HP section from 168,000 pph to 221,000 (a 31.5 percent increase) by modifying the existing steam path and converting the unit to eliminate the LP section from operation. This would allow the generation of up to the generator rating of 6250 kW at a PF of 1.0. The inlet and new exhaust flanges are large enough that no major steam piping modifications or area additions would need to be required based on the information supplied. The modified unit would also require a controls modification or upgrade to run in its new straight noncondensing configuration.

This preliminary assessment would need to be confirmed by opening up the unit for measurements and inspection. Such a measurement and inspection would cost on the order of $200,000. Based on anticipated steam path changes of replacing five sets of HP buckets and nozzles, adding a blanking plate, removing the LP blading, replacing valves, replacing the gland seal condenser, performing a high speed rotor balancing, providing new controls, and replacing the LP bearing if required, it is estimated that this service would cost on the order of $1.2 million (exclusive of the inspection). Considering that this modification could result in approximately 2 MW of additional capacity, and for a total cost of approximately $1.4 million, the specific cost of this incremental capacity is approximately $700/kW. This is much more cost effective than the replacement STG discussed in the previous section.

The measurement/inspection could be performed in about 1 week's time working day shifts only. Parts could be available for installation approximately 34 weeks after being ordered. The conversion itself would require the STG to be off line for about 8 to 10 weeks during which the rotor would be removed, shipped to the fabricator's shop, modified, returned and installed. The schedule could be accelerated, if necessary, by replacing the existing rotor with a new one. This would shorten the TG-1 offline time to the duration required to remove and install the new rotor, but would somewhat increase the cost.

In conclusion, this option appears to be a feasible, economic repair/modification option that would recover lost power associated with the reduced 10 psig steam demand. Additional consideration should be given to ensuring that the additional 100 psig steam will fit satisfactorily with the anticipated plant operational modes considering the total steam demand, coincident electric demand and the operation of the other turbines. This point is made because non-condensing machines can only produce power when the steam demand is sufficient. Of course, the advantage of non-condensing machines is that they are more efficient than condensing machines since there is no heat rejection to the condensers, and that no condenser (e.g., ACC) is needed.

6.3.11. STG-2 repair/modification considerations

A possible option for the STG-2 is to return it to active service by proper assessment, repair and modification.* The historical reasons for it being abandoned in place are not fully known. It is understood that the turbine was allowed to sit with water in it roughly 30 years ago (GE Undated), although the extent of damage is not known. Subsequently, during the 2001 upgrade project, the steam supply to STG 2 was cut off and capped at the take off to STG-1. The 200 psig extraction piping that was routed from STG-2 to the facility laundry, has been removed. In addition STG-2 no longer has any related switchgear or breaker points on any of the 12.47 kV or 4160V Busses.

Another issue for the STG-2 is that it was designed for direct cooling with circulating water supplied by the cooling pond. The present ACC project is only retrofitting STG-3 to 5. It is assumed that an ACC would also be required† should this unit be returned to service as a condensing unit. The ACC project for 3x 5MW STG was approximately $30 million, so an ACC for the 2 MW STG could add on the order of $6 million. Siting of the ACC may be an issue, since the space to the North of the existing ACC project may be tight. Alternately, it may be possible to tie the STG-2 exhaust into ducting for one of the ACC's built for TG-3 to 5. The potential for this would require additional analysis. Limited information was obtained during this project regarding STG-2, which did not allow further evaluation of this option.

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* No matter what the cause of abandonment/inoperability, these 1950 vintage GE machines were designed to be repairable. Should it be desirable to further investigate this option, and since the unit has been sitting for years, a condition assessment would be the first step in considering this option. Water sitting in the turbine would not necessarily create an irreparable problem. The rotor could be grit blasted and Mag tested. According to TurboCare, roughly 90 percent of all similar steam turbines have had drains back up and water spill over. Cracked turbine rotors are a relatively expensive repair, but it is rare for them to crack on this type of machine. The generator assessment is also a priority assessment area as their repair costs can be substantial. For example, a stator rewind could cost on the order of $500,000 to $750,000. Therefore a condition assessment of the generator would include a Meger test (test of the insulation integrity), a DC leakage test, and visual inspection of the field. Should a condition assessment be desired for STG-2, it is estimated that a combined inspection/overhaul would cost approximately $250,000 plus parts and repairs (teleconference with Kevin Lord, 22 June 2006).

† Since the ACC project was implemented to get rid of the fogging/freezing problem, it is unlikely that continued use of the cooling pond would be acceptable for STG-2, even though it is only 2 MW instead of 15 MW represented by STG-3 to 5. In fact, this small size and being only a single heating source for the cooling pond would mean the pond would likely freeze. As such, use of the cooling pond is not considered feasible for STG-2.

In review, because of the many hurdles against the STG-2 Repair/Modification, it is deemed more likely that an installation of a larger replacement machine would be more desirable than repairing the 2MW steam turbine since many of the items required for reconnecting the existing unit would need to be done for a larger replacement unit. For this reason, this option is not recommended for further analysis.

6.3.12 Short-term option summary

Table 41 lists the short term options presented in Section 6.3. The most promising options to meet the needs of FWA are increasing transformer/substation capacity. While several transformer capacity upgrade options were evaluated, only the 20 MVA option (a subset of Option 2) and the 2x20 MVA new substation options (Option 4) fully meet or exceed the incremental electric power requirements projected. Option 4 has the advantage of being able to meet the full requirements of FWA in 2020 with 100 percent backup capability. In addition, having two transformers rather than one provides an additional level of reliability if one of the transformers should happen to fail or need service. The disadvantage of this option as compared to the single 20 MVA transformer option is its higher capital cost. The options that appear to be worth examining to provide small capacity increases include:

- *Option 5—Automated VAR Compensation* would provide perhaps 2.5 MW at low cost, with minimal impacts on the plant.
- *Option 11—Modifying STG 1* to enable it to provide 5 MW rather than 3 MW, would enable use of available boiler capacity at modest cost. This option would also help to minimize the electric purchases from the grid, thus helping to minimize overall costs.
- *Option 7* also provides a small amount (3 MW) of additional power. It may be worth pursuing; however, the amount of extra power available from Eielson AFB will likely vary over time, and cannot be confidently relied on over a long period of time (e.g., to 2020).
- The other options are either not feasible or have drawbacks as discussed previously and summarized in Table 41.

Table 41. Options for short term implementation (POM 2008–2013).

Criteria/Option	1	2	3	4	5	6	7	8	9	10	11
	Purchase DG Gen Sets	Buy/Install Permanent 10 MVA transformer	2x10 MVA substation. Mobile	Purchase Substation (2x20 MVA transformer)	VAR Compensation	Separate Power Line from Clear AFS	Wheel Power from Eielson AFB	Replace 1-2 STG from Elmendorf	Add 1-2 STG from Elmendorf	Replace STG-1 and 2 with New STG	Repair/Modify STG-1
Incr. power (MW)	~5.5	8.5-9	18-19	36-38	TBD ~2.5 (10% of 25 MW)	10	3	4.3–13.6	18.6	6-7	~2 MW
Capital cost	$4.6 million	$1.3 million	Very high	$9.3 million	Low	$32 million	Low	Unknown	Unknown	$45 Million	Low ($1.4M)
Life cycle cost	High	Medium	Medium	Medium	Low	High	Low	NA	NA	Medium	Low
Operational consideration	New Procedures	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes	Requires evaluation	Requires evaluation
Environmental	Requires Evaluation	None	None	None	None	Requires evaluation	None			Requires evaluation	Requires evaluation
Time frame	2 years	50 weeks	52 weeks	52 weeks	Not evaluated	Not determined	2-4 months			2 years	1 year
Risk	Medium	Low	Low	Low	Low	Low	Medium	High	High	Low	Low
Reliability	Good	Good	Fair	Good	Low	Unknown	Same as existing	Unknown	Unknown	Good	Good
Other advantages	Increases redundancy	Could be sized and coordinated with Long Term objectives.		Could be sized and coordinated with Long Term objectives.	Low cost partial solution	Increases reliability with redundancy	May be commercial advantages–lower electricity prices than GVEA sources		Re-use government equipment		Use existing equip. Minimal impact to CHPP
Other disadvantages	Environmental issues may limit operation.	Requires same equipment as GVEA transformer	GVEA can remove for emergencies elsewhere	May be cheaper to use GVEA HV equipment	This has a limited capacity, but may be a partial solution	Major regulatory/permitting hurdles for siting power line	Requires same equipment as GVEA transformer	Space considerations	Many issues: Cooling, space, requires steam supply analysis.	Requires demoing STG-1, and numerous mods to CHPP.	This has a limited capacity, but may be a partial solution
Overall feasibility/likelihood of success	Low	Promising–for 20 MVA size	Not a permanent solution	Promising	Promising–but only provides a small increment of capacity	Low	Medium–High, but only meets a small porting of load.	Not feasible	Not feasible	Technically feasible but high cost	Promising–but provides only a small increment of capacity

Definitions of Criteria:

- *Incr. Power (MW)*: The total incremental power target for the short term option is 12.7 MW (assuming unscheduled outage of one 5 MW STG, no back door intertie, and no temperature based load increase for the existing transformer). The planning target assuming temperature based load increase is 9.7–11.2 MW.
- *Capital Cos:* This is the total capital cost of the option. There is not absolute cost limit. However, lower cost options are preferred.
- *Life Cycle Cost:* The options with the lowest lifecycle cost are to be favored
- *Operational Consideration:* This is to capture operational impacts and/or changes that should be considered in the evaluation
- *Environmental:* This includes environment limits/concerns or issues that may delay or limit the operation of the subject options.
- *Time Frame:* The time frame to implement the option.
- *Risk:* This generic risk criteria includes technical (feasibility, operational, reliability, etc.), cost and financial risk areas.
- *Reliability:* The factor reflects the reliability of the option itself and/or the ability for the entire system to be reliable.
- *Other Advantages:* Other areas as documented.
- *Other Disadvantages:* Other areas as documented.

7 Identify Methods for Improving Electrical Reliability

This chapter discusses the methods Fort Wainwright could use to improve reliability of the electrical system while meeting Short Term load requirements.

7.1 Increased reliability

The electrical systems can be made more reliable by replacing equipment most likely to fail, and/or installing redundant equipment where the consequences of the equipment failure are unacceptable. The components of the electrical system with the greatest impact on the ability to supply electrical energy are:

- Utility Transmission, Distribution and Generation (cf. Appendix A)
- Utility Intertie
- CHPP Generators
- 12.47 kV Base distribution system (cf. Appendix C)
- 12.47 kV CHPP distribution system.

The following sections discuss these components in detail.

7.1.1 Utility transmission, distribution and generation

Fort Wainwright is currently connected to the GVEA utility system (only). The reliability of the GVEA system is beyond Fort Wainwright's direct control, although the overall reliability of the GVEA system is good, at greater than 98 percent availability. GVEA wheels electrical energy from local and remote generation sources, the local generation sources are adequate for Fort Wainwright's present requirements. A utility system with local generation meeting local demand and with remote generation also available is generally more reliable than other alternatives (local or remote generation only).

Utility transmission systems typically are more reliable than the distribution systems, and this is true for the GVEA system. The increased reliability is due to several factors, including methods of construction, maintenance activities, increased system protection and a reduced number of connections. As a result, Fort Wainwright's electrical systems reliability could be increased somewhat by replacing the existing 69 kV to 12.47 kV (distribution) intertie with a 138 kV-12.47 kV (transmission) intertie.

Typically if an increase in reliability of the utility source is required, it is accomplished using redundancy, by adding another Utility intertie. The greatest increase in reliability would be obtained by connecting to another utility or generation source. There are no other utilities in the area so this does not appear to be an economically viable alternative. A second connection to the GVEA system could be made to the transmission or distribution system. A new connection to the GVEA 138 kV system would increase the Base reliability through redundancy and by using components that are more reliable.

7.1.2 Utility intertie

The reliability of the existing utility intertie could be increased by replacing aged components or by redundancy. The major components of the intertie, the GVEA distribution substation, GVEA distribution line, GVEA 7.5 MVA transformer, CHPP medium voltage cable, and CHPP 12.47 kV have been characterized as aged. The 12.47 kV switchgear is considered in Section 7.1.5. The existing 7.5 MVA GVEA intertie does not have adequate capacity to meet short term load requirements, particularly if plausible failures are considered. The CHPP medium and high voltage cable should be inspected to determine their condition. The reliability of the utility intertie could be increased through redundancy by adding a second utility intertie. Installing one new 20 MVA intertie in place of the existing 7.5 MVA intertie will not by itself significantly increase reliability.

The new high voltage equipment and transformer, however, would be less likely to fail than the corresponding existing equipment. If a new 20 MVA intertie is connected to a new 138 kV GVEA connection point, there would be a small increase in reliability, since the 138 kV system is somewhat more reliable than the 69 kV system. If the existing 7.5 MVA intertie were upgraded to 20 MVA **and** a redundant 20 MVA supply is connected to the 138 kV system, the base electrical system would be more reliable and would allow greater operational flexibility.

7.1.3 CHPP generators

The reliability of the CHPP generators could be increased by replacing aged components and implementing preventative maintenance activities. Increasing the reliability using redundancy is a feature of the existing

CHPP design. The decision to add generation should be made based on capacity requirements as opposed to reliability factors.

7.1.4 12.47 kV Fort Wainwright base distribution system

The condition of the existing base pole line and underground 12.47 kV distribution system is presented in Appendix C. The reliability of the system can be increased by replacing aged equipment.

7.1.5 12.47 kV CHPP distribution system

The critical components of the CHPP 12.47 kV distribution system are the medium voltage cables and the 12.47 kV switchgear. The reliability of the system can be improved by assessing the condition of the medium and high voltage cables and replacing the 12.47 kV switchgear. Replacing the existing 12.47 kV Switchgear is recommended to meet the short term load requirements. Replacing this equipment will increase reliability (and safety).

The reliability can be further enhanced by including redundancy in the switchgear configuration. Using a new double ended switchgear with two main incoming lines would increase reliability by replacing aged components and by providing redundancy in the design (two main incoming lines). If the 12.47 kV switchgear is arranged for a new, redundant GVEA intertie it would allow for continued operation with either GVEA intertie (in the event that one interties connection were lost). The configuration would also provide more flexibility in construction and maintenance activities by allowing planned outages of either utility intertie. Installing black start diesel generators would increase reliability by providing the capability of re-starting the CHPP generators if the GVEA system failed and the CHPP generators were taken off line.

8 Conclusions and Recommendations

8.1 Conclusions

This study concludes that Fort Wainwright's electrical system can be made more reliable by replacing aged components and including redundancy in the new equipment and electrical system configuration. Section 6.3.4 of this report describes a design approach to incorporate needed features. A second (very similar) detailed approach authored by CEHNC personnel is included in Appendix C to this report.

8.2 Recommendations

This work recommends that Fort Wainwright's electrical system be improved by implementing the following specific items:

- replace existing 12.47kV switchgear
- add new utility intertie to 138kV System
- upgrade existing 7.5MVA intertie
- add black start diesel generators
- conduct condition assessment of CHPP medium and high voltage cables (complete in conjunction with item 1).

It is further recommended that the Fort Wainwright implement a preventative maintenance program to keep electric system equipment in the condition recommended by the original equipment manufacturers. A related report (e-mail from Pat Driscoll to William Brown 16 June 2006) evaluating the maintenance and reliability at Fort Wainwright includes several lists of recommended maintenance activities for the electric system equipment. These maintenance activities should be followed.

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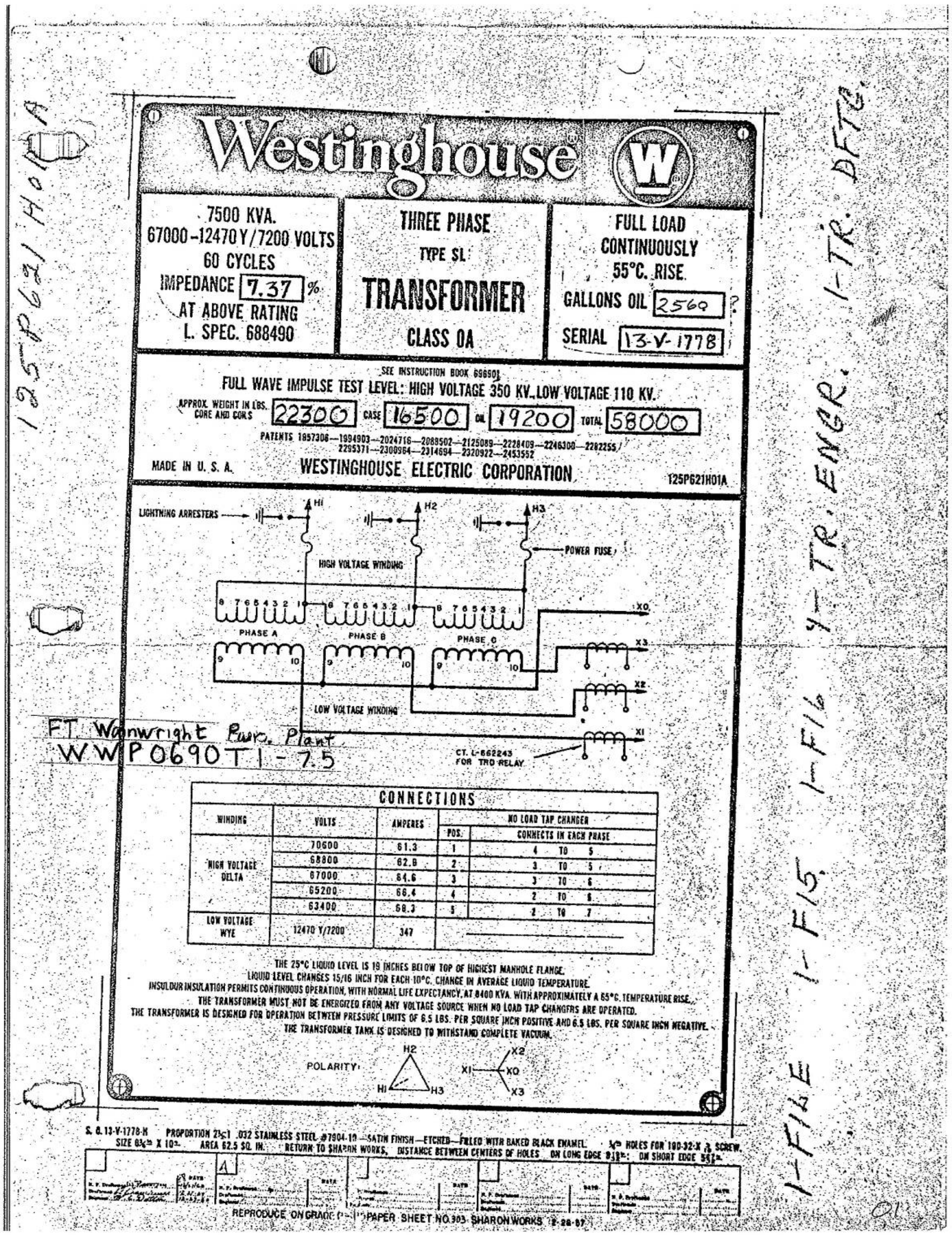
ZBA, Inc. Engineers/Consultants. Undated. *Drawing F26-02-40, interim repairs, mechanical, floor plan elevation 115 ft, 0 in., 9/9/1999, file 1633M05.*

Appendix A: Results of Conversation with GVEA on 9 May 2006

	Questions	Answers
1.00	Lists of questions for GVEA	
1.01	Number of GVEA Electric Points of Service/Ties to the installation	See Below
1.02	Capacity of each existing point of service (tie)	See Below
1.03	Characteristics of Point of Service (Voltage, amperes, kVA, equipment type and age)	There are 3 ties: 1. The connection to the CHPP through the 69KV-12.47KV GVEA 7.5MVA OA transformer 2. A connection to a small portion of base housing, this portion of base housing is served solely by GVEA and is not connected to the base distribution system. 3. A back door tie. The back door tie is intended to be used for emergency purposes and must be switched in manually. The capacity is approx 5MW
1.04	Limitations on the Ties/connections (Physical/contractual). Potential for increasing supply to FWA through these connections.	The 12.47KV base housing tie and back door tie are limited by the capacity of the existing lines and to the capacity available in the substation. Some additional capacity does exist. The back door tie could possibly be increased to about 600A. The 69KV tie to the GVEA transformer is limited to approx 30MW of additional power.
1.05	Capacity of GVEA transmission system for supply to Base (total capacity, excess capacity)	The current available capacity is about 28-36 MW
1.06	Capacity of GVEA generation and ability to serve FWA	30MW
1.07	GVEA reliability data for the points of service to FWA	Can be obtained
1.08	Limitations on GVEA transmission line interconnections with Anchorage	GVEA currently uses the tie line to Anchorage to supplement its energy demand. The power purchased from anchorage is at a lower cost than that generated locally, but the tie line is not required to meet the local demand.
1.09	Future GVEA projects that could impact available capacity to base	On Going projects
1.10	Other electrical power sources in the area	GVEA can supply an emergency substation with 20MW capacity, GVEA would retain the right to use the substation in case of emergencies at other locations. It may be possible for the base to enter into wheeling agreements
1.11	Metering data on Ties	Can be obtained

Appendix B: GVEA Transformer Nameplate



125P621H01A

Westinghouse

7500 KVA.
67000-12470Y/7200 VOLTS
60 CYCLES
IMPEDANCE 7.37 %
AT ABOVE RATING
L. SPEC. 688490

THREE PHASE
TYPE SL
TRANSFORMER
CLASS OA

FULL LOAD
CONTINUOUSLY
55°C. RISE
GALLONS OIL 2560 ?
SERIAL 13-V-1778

SEE INSTRUCTION BOOK 696901
FULL WAVE IMPULSE TEST LEVEL: HIGH VOLTAGE 350 KV. LOW VOLTAGE 110 KV.
APPROX. WEIGHT IN LBS. CORE AND COILS 22300 CASE 16500 OIL 19200 TOTAL 58000
PATENTS 1857306—1994903—2024716—2088502—2125089—2228409—2246300—2282255
2295371—2300964—2314694—2320922—2453552
MADE IN U. S. A. WESTINGHOUSE ELECTRIC CORPORATION 125P621H01A

LIGHTNING ARRESTERS
H1 H2 H3
POWER FUSE
HIGH VOLTAGE WINDING
8 7 6 5 4 3 2 1
PHASE A PHASE B PHASE C
9 10
X0 X3 X2 X1
LOW VOLTAGE WINDING
CT. L-662243 FOR TRO RELAY

FT. Wainwright Pwr. Plant
WWP0690T1-7.5

CONNECTIONS

WINDING	VOLTS	AMPERES	NO LOAD TAP CHANGER	
			POS.	CONNECTS IN EACH PHASE
HIGH VOLTAGE DELTA	70600	61.3	1	4 TO 5
	68800	62.8	2	3 TO 5
	67000	64.6	3	3 TO 6
	65200	66.4	4	2 TO 6
	63400	68.3	5	2 TO 7
LOW VOLTAGE WYE	12470 Y/7200	347		

THE 25°C LIQUID LEVEL IS 19 INCHES BELOW TOP OF HIGHEST MANHOLE FLANGE.
LIQUID LEVEL CHANGES 15/16 INCH FOR EACH 10°C. CHANGE IN AVERAGE LIQUID TEMPERATURE.
INSULDUR INSULATION PERMITS CONTINUOUS OPERATION, WITH NORMAL LIFE EXPECTANCY, AT 8400 KVA. WITH APPROXIMATELY A 65°C. TEMPERATURE RISE.
THE TRANSFORMER MUST NOT BE ENERGIZED FROM ANY VOLTAGE SOURCE WHEN NO LOAD TAP CHANGERS ARE OPERATED.
THE TRANSFORMER IS DESIGNED FOR OPERATION BETWEEN PRESSURE LIMITS OF 6.5 LBS. PER SQUARE INCH POSITIVE AND 6.5 LBS. PER SQUARE INCH NEGATIVE.
THE TRANSFORMER TANK IS DESIGNED TO WITHSTAND COMPLETE VACUUM.

POLARITY: H1 H2 H3 X1 X0 X2 X3

S. O. 13-V-1778-K PROPORTION 2½:1 .032 STAINLESS STEEL #7904-10—SATIN FINISH—ETCHED—FILLED WITH BAKED BLACK ENAMEL. HOLES FOR 100-32-X SCREW.
SIZE X 10 AREA 62.5 SQ. IN. RETURN TO SHARON WORKS. DISTANCE BETWEEN CENTERS OF HOLES ON LONG EDGE : ON SHORT EDGE

A

REPRODUCE ON GRADE PAPER SHEET NO.303 SHARON WORKS

1-FILE 1-F15 1-F16 4-TR. ENGR. 1-TR. DFTG.

Appendix C: Fort Wainwright, Alaska Electric Power System Assessment Prioritization and Validation of Funding Requirements.

Introduction

The U. S. Army Corps of Engineers, Engineering and Support Center, Huntsville (CEHNC) was tasked with prioritizing and validating a request for funding of replacement/renewal (recapitalization) of the Fort Wainwright, Alaska (FWA) electrical system. During the week of 7 May 2006, we performed a limited inspection, interviews with FWA personnel, and condition evaluation. Our overall assessment is that the FWA electric system is in need of recapitalization and upgrade. It was apparent that some recent investment has been made and work performed to replace system components and equipment, however, there is much more that needs to be done to ensure electric reliability and availability. The FWA Directorate of Public Works staff appears to be very knowledgeable, capable, and diligent, but are not staffed or equipped to accomplish the necessary work with their in-house personnel.

The electric distribution system consists of poles, fixtures, guys/anchors, overhead and underground conductors, street lighting (poles, circuits, and fixtures); airfield lighting, transformers, and the distribution switchgear in the CHPP. The critical electric equipment examined on the CHPP side of the system consisted of the generator switchgear, generator controls, and the substation tie with Golden Valley Electric (GVEA).

CEHNC has developed an estimate that includes the following systems, components, and equipment:

- CHPP 12.47 kV switchgear (generator and distribution) and controls
- GVEA intertie substation
- Overhead and underground 12.47 kV distribution system
- Airfield lighting system (runway, approach, taxiway, etc.)
- Streetlights (roadway, street, and area lights served from the distribution system).

Black-start generating plant

The estimate is based on the expectation that this work will be accomplished as design-build type repair/remediation, and that specific work plans will be developed to implement the corrective actions. Development of work plans will require field surveys to provide designs and specifics of remediation.

The cost values do not represent total replacement of the entire exterior electric distribution system. The figures are an educated guess at the replacements and upgrades necessary to bring the system up to a "serviceable level" (approximately 80 percent remaining life).

Assessment

Physical observation shows that:

- The CHPP switchgear is the original mid-1950s equipment (manufactured in 1956). It is in need of refurbishment right away, and total replacement as soon as possible.
- The CHPP plant control system was updated in the early 1990s, using mid 1980s technology, however, the generator and distribution monitoring and controls were not included in the update and are 1950s technology. Replacement/upgrading of the switchgear will require an upgrade of the plant monitoring and control system to current system technology to ensure compatibility.
- There are 10 circuits feeding from the CHPP, of mixed wire sizes, ages, and conditions. The system should be re-designed, circuits consolidated to form a "backbone" system, reconductored with large wire, and provided with multiple tie-points.
- A limited number of poles in the overhead distribution system have been replaced, but a large number are past their useful lives and should be replaced.
- Limited replacement/rework of parts of the existing system has been accomplished through new building projects.
- Most of the airfield lighting system is in need of immediate upgrade/replacement because the circuit conductors are at the end of their useful lives, and the lighting fixtures are obsolete and replacement parts are either hard to procure or cannot be procured commercially.
- The GVEA Intertie is aged, limited in capacity, and should be replaced.
- Much of FWA does not have adequate street lighting. The street lighting system is a mixture of aged and new equipment of varying types

and manufacture. Obsolete fixtures should be replaced and some lower lumen fixtures should be replaced to provide adequate lighting for roadways. Many of the wooden poles for street and area lighting are damaged, rotten, or beyond their useful lives and should be replaced.

- The CHPP needs a "black-start" diesel engine generating plant to bring the plant back online in case of loss of the GVEA tie. Currently, the GVEA tie is the only method of starting the plant if all generators trip offline. Also, there are scenarios where the GVEA tie could be lost and cause simultaneous trip of the CHPP generators (e.g., there is a fault on the GVEA 69 kV feeder to the plant).

Cost model

The Corps of Engineers, Engineering and Support Center, Huntsville developed costs for replacement and renewal of the electric utility system (Table C1) based on the following approach:

1. <u>Replace the CHPP Generator Switchgear and Distribution Switchgear (includes new 60 x 80-ft switchgear enclosure in CHPP)</u>: Upgrade the CHPP Control System to make it compatible with the new switchgear, incorporating current state-of-the-art controls and monitoring equipment (including 40-ft x 60-ft Control Room).
2. GVEA–CHPP Substation: Replace the current substation (7.5 MVA, 69 kV-12.47 kV) with a new substation (30 MVA, 69 kV-12.47 kV). The new substation is configured to include two 15 MVA transformers, high voltage circuit interrupters, metering, protective relays, and two medium voltage vacuum circuit breakers. Government ownership of the transformers is recommended because of the rate advantages.
3. Airfield Lighting: Replace the electrical system (entire system) and lighting fixtures. Upgrade to LED technology.
4. Exterior Distribution:
   a. Overhead Distribution:
      (1) Reconfigure/re-conductor (larger wire size) the electric feeder configuration on the installation to establish a "backbone" system with loop feeds to ensure operability (approximately 20 miles).
      (2) Replace all copper primary (12.47kV) conductors.
      (3) Update Load Flow and Voltage Drop Study, and develop Fault Analysis and Protective Device Plan, and Phase Rotation Check.
      (4) Examine all poles, identify and replace rotten/degraded poles (target 675–700 pole replacements).

(5) Examine all down guys and anchor rods, tighten guys, and install yellow plastic guy markers.
(6) Examine all pole grounds and install plastic ground guards. Repair broken conductors. Replace grounds affected by pole replacement.

5. Underground Distribution: Perform limited repair of manholes and limited replacement of underground conductors (Identify from plant records, failure reports, examination).
   a. Street Lights: Perform maintenance (clean/relamp) for street and roadway lighting. Replace broken/obsolete fixtures (Budget 950 fixtures).
6. Black-Start Generator Plant: Install two 1.5 MW diesel engine generators (4.16 kV) in a conditioned building within 600 ft of the CHPP. The estimated includes a 60 x 80-ft engineered metal building, paralleling switchgear, 150-gal day tanks, 500-gal main fuel tank, fire detection, remote CCTV monitoring,

System information

The FWA Property Books portray the FWA system as 705,931 (linear) ft of electrical distribution lines, and 36 breakers, 7500 kVA each. The inventory prepared for Utilities Privatization describes the system as listed in the tables below. The Privatization documents represent that the system is of varying age, but that many of the basic components are nearing the end of their useful lives. The Utility Privatization data was assumed to have been developed in 1996–2000 and not significantly updated to reflect additions and replacements since that time.

Table C1. Recommended priority of tasks and estimated costs

Priority	Task	Estimated Cost
1	Replace Electrical Switchgear and Upgrade Control Room	$21,654,770
2	Replace 69 kV Substation (From 7.5–30 MVA)	$7,825,241
3	Replace Airfield Lighting	$13,928,408
4A	Replace Overhead Electrical Distribution	$16,066,718
4B	Replace Underground Electrical Distribution	$3,336,245
4C	Replace Street Lighting	$2,550,957
5	Install Generators and Switchgear (Black Start)	$9,407,511
	Total	***$74,769,851***

Table C2. Inventory prepared for utilities privatization.

Overhead Lines	Quantity	Used Life
3 Phase–Open Wire Large	9.67 mi.	66%
3 Phase–Open Wire Small	61.14 mi.	80%
1 Phase–Open Wire	4.64 mi.	80%
Gang Operated Air Break Switch	45	63%
Secondary	19.84 mi.	74%
Underground Lines		
3 Phase–Large	0.20 mi.	60%
3 Phase–Small	5.47 mi.	80%
1 Phase–Direct Buried	0.41 mi.	80%
Duct	0.41 mi.	80%
Manhole	0	0%
Pad-mounted sectionalizing switch	1	80%
Secondary	1.22 mi.	33%
Transformers–Pole Type		
15 kVA and smaller	215	64%
25 kVA	270	70%
37.5 kVA	103	76%
50 kVA	187	74%
75 kVA	90	64%
100 kVA	54	68%
Transformers–Pad Mount		
1P–15 kVA and smaller	14	50%
1P–25 kVA	16	58%
1P–50 kVA	8	54%
1P–75 kVA	2	70%
1P–100 kVA	7	58%
1P–167 kVA	2	70%
1P–833 kVA	6	50%
3P–112.5 kVA and smaller	9	4%
3P–150 kVA	3	52%
3P–225 kVA	12	58%
3P–300 kVA	7	50%
3P–500 kVA	12	46%
3P–600 kVA	1	30%
3P–750 kVA	12	52%
3P–1000 kVA	4	38%
3P–1500 kVA	0	0%
3P–2000 kVA	1	28%
Street Lights		

Overhead Lines	Quantity	Used Life
St. Light Circuits	2.11 mi.	80%
Fixtures with Poles (no conductor on map)	426	80%
Fixtures with Poles	318	80%
Fixtures without Poles	222	80%
Airfield Lighting		
Diesel Generator incl. ATS and day tank	1	80%
Load Interrupter Switch, 5kV	3	80%
Runway Edge Lights	170	80%
Taxiway Lights	415	80%
Rotating Beacon	1	80%
Beacon Tower	1	80%
Series/Isolation Transformers	585	80%
Constant Current Regulator, 20KW	1	80%
Constant Current Regulator, 50KW	6	53%
Constant Current Regulator, 4KW	6	80%
Control Panel	8	80%
Runway Lighting Cable	74,008 LF.	80%
Elevated Approach Bar	2	80%
Flasher, Sequential	2	80%
Runway Manholes, Access, U/G cable	26	80%
Handhole	525	64%
Switchgear/Transformer building	1,250	64%
Ductbank, 4-in. PVC, 1X1	33,852 LF	64%
Ductbank, 4-in. PVC, 1X2	22,110 LF	64%
Ductbank, 4-in. PVC, 2X2	990 LF	64%
Ductbank, 4-in. PVC, 2X3	278 LF	64%
Ductbank, 4-in. PVC, 3X4	708 :LF	64%
MV Switchgear		
15kV Air-Circuit Breaker	24	80%
5kV Air-Circuit Breaker	4	80%
15kV Vacuum-Circuit Breaker	12	8%

Cost estimate details

Ft Wainwright, AK
Switchgear/Control Room
5/24/2006

	Qty	UOM	Labor	Material	Equipment	Shipping	*FAC Unit Cost w/ ACF	Total Cost	
Primary Facility									
Metal Building Electrical Switchgear	6000	SF	$ 26,280	$ 46,350	$ 17,550	$ 12,000	$ -	$ 102,180	
Power & Lighting	1	LS	$ 12,625	$ 22,375	$ -	$ -	$ -	$ 35,000	
Switchboard	1	LS	$ 500	$ 10,000	$ -	$ -	$ -	$ 10,500	
CCTV	1	LS	$ -	$ -	$ -	$ -	$ -	$ 10,000	Allowance
Fire Protection	6000	SF	$ -	$ -	$ -	$ -	$ 25,200	$ 25,200	
Heating & Cooling	1	EA	$ 6,000	$ 19,000	$ 600	$ 1,200	$ -	$ 26,800	
15 kV Switchgear	1	LS	$ 333,671	$ 3,813,379	$ 64,065	$ 72,000	$ -	$ 4,283,114	
Power Feeders	1	LS	$ 145,465	$ 698,670	$ 1,050	$ 4,000	$ -	$ 849,185	
Control Wiring	1	LS	$ -	$ -	$ -	$ -	$ -	$ 15,000	Allowance
Demolition Electrical	1	LS	$ 22,000	$ -	$ 500	$ -	$ -	$ 22,500	
Subtotal Elect Swgr								**$ 5,379,479**	
Metal Building Control Building	2400	SF	$ 10,512	$ 18,540	$ 7,020	$ 5,000	$ -	$ 41,072	
Power & Lighting	1	LS	$ 5,100	$ 9,000	$ -	$ -	$ -	$ 24,000	
Switchboard	1	LS	$ 1,200	$ 10,000	$ -	$ -	$ -	$ 11,200	
Fire Protection	1	LS	$ -	$ -	$ -	$ -	$ -	$ 10,000	Allowance
Heating & Cooling	1	EA	$ 2,300	$ 7,600	$ 400	$ 800	$ -	$ 11,100	
Control Wiring	1	LS	$ -	$ -	$ -	$ -	$ -	$ 5,000	Allowance
Work Stations	6	EA	$ 1,600	$ 96,000	$ -	$ 6,000	$ -	$ 103,600	
Monitors	6	EA	$ 900	$ 18,000	$ -	$ -	$ -	$ 18,900	
Demolition Electrical	1	LS	$ 5,000	$ -	$ -	$ -	$ -	$ 5,000	
Subtotal Control Bldg								**$ 229,872**	
Subtotal			**$ 573,153**	**$ 4,768,914**	**$ 91,185**	**$ 101,000**	**$ 25,200**	**$ 5,609,351**	
Labor Adjustment and Productivity			343,892					$ 343,892	
Vendor Representative	1	LS						$ 50,000	
Subtotal			$ 917,044					**$ 6,003,243**	
Subcontractor Markups	30%							$ 1,800,973	
Total Subcontractor Cost								**$ 7,804,216**	
Prime Project Management	14%							$ 1,092,590	
Prime Project ODC	16%							$ 1,248,675	
Testing & Commissioning	5%							$ 390,211	
Prime Contractor Markups	20%							$ 2,107,138	
Total Est Construction Cost								**$ 12,642,830**	
Scope Allowance	30%							$ 3,792,849	
Total w/ Allowance								**$ 16,435,679**	
Engineering Design Build Cost	8%							$ 1,314,854	
Total Construction & Engineering								**$ 17,750,533**	
Gov't Contingency	5%							$ 887,527	
Gov't SIOH	8%							$ 1,491,045	
Subtotal								**$ 20,129,104**	
DDC	2%							$ 402,582	
Construction Working Estimate								**$ 20,531,687**	
** Escalation	5.47%							$ 1,123,083	
Program Amount								**$ 21,654,770**	

* Facility Unit Costs - Military Construction dated 15 Mar 2005. ACF for Fairbanks is 2.13.
** Escalation base on construction start Mar 2008 with completion in Nov 2009.

Ft Wainwright, AK
Substation
5/24/2006

	Qty	UOM	Labor	Material	Equipment	Shipping	* FAC Unit Cost w/ ACF	Total Cost
GVEA 69 kV Overhead Line	1	LS	$ -	$ -	$ -	$ -	$ 179,900	$ 179,900
69 kV Xformer 15 MVA w/ Tap Changer	2	EA	$ 13,164	$ 670,000	$ 1,600	$ 120,000	$ -	$ 804,764
69 kV Gang Operator Switch	2	EA	$ 7,000	$ 57,200	$ 2,600	$ 12,000	$ -	$ 78,800
69 kV Distribution Bus	2	EA	$ 20,000	$ 60,000	$ 12,000	$ 12,000	$ -	$ 104,000
Power Metering	2	EA	$ 800	$ 62,000	$ -	$ 800	$ -	$ 63,600
12.47 kV Main Breaker Switchgear	2	EA	$ 12,000	$ 130,000	$ 4,000	$ 20,000	$ -	$ 166,000
12.47 kV Electrical Ductbank	1	LS	$ -	$ -	$ -	$ -	$ 90,000	$ 90,000
12.47 kV Electrical Hand Hole	4	EA	$ 6,600	$ 8,400	$ 4,600	$ -	$ -	$ 19,600
12.47 Electrical Cables	2	EA	$ 40,600	$ 102,200	$ -	$ 12,000	$ -	$ 154,800
Transformer/Switchgear Pads	1	LS	$ 300	$ 1,500	$ 200	$ -	$ -	$ 2,000
Fences 10' High	1	LS	$ -	$ -	$ -	$ -	$ 61,200	$ 61,200
Demo Electrical Equipment	1	LS	$ 10,000	$ -	$ 2,000	$ -	$ -	$ 12,000
Site Support	1	LS	$ -	$ -	$ -	$ -	$ -	$ 138,933
Subtotal			**$ 110,464**	**$ 1,091,300**	**$ 27,000**	**$ 176,800**	**$ 331,100**	**$ 1,875,597**
Labor Adjustment and Productivity			66,278					$ 66,278
Vendor Representative	1	LS						$ 150,000
Subtotal			$ 176,742					**$ 2,091,875**
Subcontractor Markups	30%							$ 627,563
Total Subcontractor Cost								**$ 2,719,438**
Prime Project Management	14%							$ 380,721
Prime Project ODC	16%							$ 435,110
Testing & Commissioning	10%							$ 271,944
Prime Contractor Markups	20%							$ 761,443
Total Est Construction Cost								**$ 4,568,656**
Scope Allowance	30%							$ 1,370,597
Total w/ Allowance								**$ 5,939,253**
Engineering Design Cost	8%							$ 475,140
Total Construction & Engineering								**$ 6,414,393**
Gov't Contingency	5%							$ 320,720
Gov't SIOH	8%							$ 538,809
Subtotal								**$ 7,273,921**
DDC	2%							$ 145,478
Construction Working Estimate								**$ 7,419,400**
** Escalation	5.47%							$ 405,841
Program Amount								**$ 7,825,241**

* Facility Unit Costs - Military Construction dated 15 Mar 2005. ACF for Fairbanks is 2.13
** Escalation base on construction start Mar 2008 and finish Nov 2009.

Ft Wainwright, AK
Distribution Airfield Lighting
5/24/2006

	Qty	UOM	Labor	Material	Equipment	Shipping	*FAC Unit Cost w/ ACF	Total Cost
Supporting Facilities								
*** Airfield Lighting	1	LS	$ -	$ -	$ -	$ -	$ -	$ 4,088,438
Subtotal			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 4,088,438**
Subcontractor Markups	30%							$ 1,226,531
Total Subcontractor Cost								**$ 5,314,969**
Prime Project Management	14%							$ 744,096
Prime Project ODC	16%							$ 850,395
Testing & Commissioning	5%							$ 265,748
Prime Contractor Markups	20%							$ 1,435,042
Total Est Construction Cost								**$ 8,610,250**
Scope Allowance	30%							$ 2,583,075
Total w/ Allowance								**$ 11,193,326**
Engineering Design Build Cost	2%							$ 223,867
Subtotal								**$ 11,417,192**
Gov't Contingency	5%							$ 570,860
Gov't SIOH	8%							$ 959,044
Subtotal								**$ 12,947,096**
DDC	2%							$ 258,942
Construction Working Estimate								**$ 13,206,038**
** Escalation	5.47%							$ 722,370
Program Amount								**$ 13,928,408**

* Facility Unit Costs - Military Construction dated 15 Mar 2005. ACF for Fairbanks is 2.13.
** Escalation base on construction start Mar 2008 with completion in Nov 2009.
*** Cost based on Privatization study updated 2005.

Ft Wainwright, AK
Distribution Overhead Lines
5/24/2006

		Qty	UOM	Labor	Material	Equipment	Shipping	*FAC Unit Cost w/ ACF	Total Cost
Supporting Facilities									
***	Electrical Overhead Lines	1	LS	$ -	$ -	$ -	$ -	$ -	$ 4,625,407
	Subtotal			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 4,625,407**
	Subcontractor Markups	30%							$ 1,387,622
	Total Subcontractor Cost								**$ 6,013,029**
	Prime Project Management	14%							$ 841,824
	Prime Project ODC	16%							$ 962,085
	Testing & Commissioning	0%							$ -
	Prime Contractor Markups	20%							$ 1,563,388
	Total Est Construction Cost								**$ 9,380,325**
	Scope Allowance	30%							$ 2,814,098
	Total w/ Allowance								**$ 12,194,423**
	Engineering Design Build Cost	8%							$ 975,554
	Total Construction & Engineering								**$ 13,169,977**
	Gov't Contingency	5%							$ 658,499
	Gov't SIOH	8%							$ 1,106,278
	Subtotal								**$ 14,934,754**
	DDC	2%							$ 298,695
	Construction Working Estimate								**$ 15,233,449**
**	Escalation	5.47%							$ 833,270
	Program Amount								**$ 16,066,718**

* Facility Unit Costs - Military Construction dated 15 Mar 2005. ACF for Fairbanks is 2.13.
** Escalation base on construction start Mar 2008 with completion in Nov 2009.
*** Cost based on Privatization study updated 2005.

Ft Wainwright, AK
Distribution Under Ground Lines
5/24/2006

		Qty	UOM	Labor	Material	Equipment	Shipping	*FAC Unit Cost w/ ACF	Total Cost
Supporting Facilities									
***	Underground Lines	1	LS	$ -	$ -	$ -	$ -	$ -	$ 558,794
	Subtotal			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 558,794**
	Subcontractor Markups	30%							$ 167,638
	Total Subcontractor Cost								**$ 726,432**
	Prime Project Management	14%							$ 101,701
	Prime Project ODC	16%							$ 116,229
	Testing & Commissioning	0%							$ -
	Prime Contractor Markups	20%							$ 188,872
	Total Est Construction Cost								**$ 1,133,234**
	Scope Allowance	30%							$ 339,970
	Total w/ Allowance								**$ 1,473,205**
	Engineering Design Cost	2%							$ 29,464
	Total Construction & Engineering								**$ 1,502,669**
	Gov't Contingency	5%							$ 75,133
	Gov't SIOH	8%							$ 126,224
	Subtotal								**$ 3,206,695**
	DDC	2%							$ 64,134
	Construction Working Estimate								**$ 3,270,829**
**	Escalation	5.47%							$ 65,417
	Program Amount								**$ 3,336,245**

* Facility Unit Costs - Military Construction dated 15 Mar 2005. ACF for Fairbanks is 2.13.
** Escalation base on construction start Mar 2008 with completion in Nov 2009.
*** Cost based on Privatization study updated 2005.

Ft Wainwright, AK
Distribution Street Lighting Lines
5/24/2006

		Qty	UOM	Labor	Material	Equipment	Shipping	*FAC Unit Cost w/ ACF	Total Cost
	Supporting Facilities								
***	Street Lights	1	LS	$ -	$ -	$ -	$ -	$ -	$ 777,588
	Subtotal			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 777,588**
	Subcontractor Markups	30%							$ 233,276
	Total Subcontractor Cost								**$ 1,010,864**
	Prime Project Management	14%							$ 141,521
	Prime Project ODC	16%							$ 161,738
	Testing & Commissioning	0%							$ -
	Prime Contractor Markups	20%							$ 262,825
	Total Est Construction Cost								**$ 1,576,948**
	Scope Allowance	30%							$ 473,085
	Total w/ Allowance								**$ 2,050,033**
	Engineering Design Cost	2%							$ 41,001
	Total Engineering & Construction								**$ 2,091,034**
	Gov't Contingency	5%							$ 104,552
	Gov't SIOH	8%							$ 175,647
	Subtotal								**$ 2,371,232**
	DDC	2%							$ 47,425
	Construction Working Estimate								**$ 2,418,657**
**	Escalation	5.47%							$ 132,301
	Program Amount								**$ 2,550,957**

* Facility Unit Costs - Military Construction dated 15 Mar 2005. ACF for Fairbanks is 2.13.
** Escalation base on construction start Mar 2008 with completion in Nov 2009.
*** Cost based on Privatization study updated 2005.

Ft Wainwright, AK
Black Start Generators
5/24/2006

		Qty	UOM	Labor	Material	Equipment	Shipping	*FAC Unit Cost w/ ACF	Total Cost	
***	Generator, diesel,1500 kW	2	LS	$ 17,040	$ 946,000	$ 4,000	$ 150,000	$ -	$ 1,117,040	Includes battery, charger, muffler, ATS & day tanks.
	Ancillary Controls	2	EA	$ 2,000	$ 26,000	$ 1,000	$ 1,200	$ -	$ 30,200	
	Switchgear 5 kV, 10 compartments	5	EA	$ 13,500	$ 132,500	$ 2,500	$ 4,000	$ -	$ 152,500	
	Vacuum Breaker 1200 Amp	3	EA	$ 3,600	$ 48,000	$ 375	$ 300	$ -	$ 52,275	
	Vacuum Breaker 600 Amp	2	EA	$ 1,600	$ 24,000	$ 250	$ 200	$ -	$ 26,050	
	Engineering Metal Building	4800	SF	$ 30,000	$ 432,000	$ 49,000	$ 9,600	$ -	$ 520,600	
	Fire Protection	4800	SF	$ -	$ -	$ -	$ -	$ 29,760	$ 29,760	
	CCTV Monitoring	1	LS	$ -	$ -	$ -	$ -	$ -	$ 10,000	Allowance
	Fuel Tank, 500 GAL, Double Wall	1	EA	$ 300	$ 12,000	$ 325	$ 1,200	$ -	$ 13,825	Includes allowance for fdn, pump & piping.
	Duct Bank, two 4-way-4"	1200	LF	$ -	$ -	$ -	$ -	$ 114,000	$ 114,000	
	Power Feeders	10.8	MLF	$ 47,500	$ 112,400	$ -	$ 1,000	$ -	$ 160,900	
	Power & Lighting	1	LS	$ 10,100	$ 17,900	$ -	$ -	$ -	$ 28,000	
	Interior Switchgear Breaker	1	LS	$ 350	$ 7,200	$ -	$ -	$ -	$ 7,550	
	Site Support	1	LS	$ -	$ -	$ -	$ -	$ -	$ 169,703	169,702.50
	Subtotal			**$ 125,990**	**$ 1,758,000**	**$ 57,450**	**$ 167,500**	**$ 143,760**	**$ 2,432,403**	
	Labor Adjustment and Productivity			75,594					$ 75,594	
	Vendor Representative	1	LS						$ 100,000	
	Subtotal			$ 201,584					**$ 2,607,997**	
	Subcontractor Markups	30%							$ 782,399	
	Total Subcontractor Cost								**$ 3,390,396**	
	Prime Project Management	14%							$ 474,655	
	Prime Project ODC	16%							$ 542,463	
	Testing & Commissioning	5%							$ 169,520	
	Prime Contractor Markups	20%							$ 915,407	
	Total Est Construction Cost								**$ 5,492,442**	
	Scope Allowance	30%							$ 1,647,733	
	Total w/ Allowance								**$ 7,140,174**	
	Engineering Design Cost	8%							$ 571,214	
	Total Engineering & Construction								**$ 7,711,388**	
	Gov't Contingency	5%							$ 385,569	
	Gov't SIOH	8%							$ 647,757	
	Subtotal								**$ 8,744,714**	
	DDC	2%							$ 174,894	
	Construction Working Estimate								**$ 8,919,608**	
**	Escalation	5.47%							$ 487,903	
	Program Amount								**$ 9,407,511**	

* Facility Unit Costs - Military Construction dated 15 Mar 2005. ACF for Fairbanks is 2.13.
** Escalation base on construction start Mar 2008 with completion in Nov 2009.
*** Emission controls are not required since generator are temporary and estimated usage is <100 hrs per year) per discussion with Sam Sang (Environmental).

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John L. Vavrin, William T. Brown, Michael R. Kemme, Marcus A. Allen, Wayne J. Percle, Robert T. Lorand, David B. Stauffer, and Kenneth Hudson

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14. ABSTRACT

Headquarters, Installation Management Command (HQ IMCOM) commissioned a study team under the leadership of the Engineer Research and Development Center, Construction Engineering Research Laboratory (ERDC-CERL), to determine the electric power requirements of Fort Wainwright, Alaska (FWA) through the year 2020, and energy supply alternatives to meet these requirements. Of particular importance was that FWA management projected that the installation might experience electrical power shortages during the impending winter of 2006/2007 due to increases in energy demand resulting from troop deployments, new construction at the installation, reduction in the number of facilities scheduled for demolition, and the temporary loss of some Central Heating and Power Plant (CHPP) generating capacity. The study team was dispatched to FWA in May 2006 to: (1) determine if there was an imminent problem, (2) identify the most promising courses of action, and (3) identify options and estimate costs to meet the installation's power requirements through the year 2020.

15. SUBJECT TERMS
Ft. Wainwright, AK; utilities; electrical distribution system; central heating and power plant (CHPP); energy consumption

16. SECURITY CLASSIFICATION OF: a. REPORT	b. ABSTRACT	c. THIS PAGE	17. LIMITATION OF ABSTRACT	18. NUMBER OF PAGES	19a. NAME OF RESPONSIBLE PERSON / 19b. TELEPHONE NUMBER (include area code)
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